The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

June 26, 1986

D.P.U. 85-266-A

Investigation by the Department on its own motion as to the propriety of the rates and charges set forth in Schedules MDPU 710, Experimental Customer Interruptible Rate SC 1, and 711, Experimental Interruptible Rate SC 2, filed with the Department by the Boston Edison Company on December 2, 1985, to become effective January 1, 1986; and

D.P.U. 85-271-A

Investigation by the Department on its own motion as to the propriety of the rates and charges set forth in Schedules MDPU Nos. 712, Terms and Conditions; 713, General Service Rate 1; 714, General Service Rate 2, General Service Rate 3; 715, General Service Rate G-2A; 716, General Service Rate G-3; 717, Optional Time-of-Use Rate T-1; 718, Time-of-Use Rate T-2; 719, Residence Rate 1; 720, Residence Rate 2; 721, Residence Rate R-3; 722, Optional Time-of-Use Rate R-4; 723, Street Lighting Energy Rate S-1; 723, Street Lighting Energy Rate S-2; 725, Outdoor Lighting Rate S-3; 726, Auxiliary Services Charges; 543, Conservation Service Charge; 727, Direct Current Charge; 687, Fuel and Purchased Power Adjustment; 728, Miscellaneous Charges; and 729, Qualifying Facility Power Purchase Rate, Filed with the Department on December 17, 1985, by the Boston Edison Company, to become effective January 1, 1986.

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I. INTRODUCTION

On December 17, 1985, the Boston Edison Company ("BECo" or "Company") filed with the Department of Public Utilities ("Department") tariff schedules of proposed rate changes under M.D.P.U. Nos. 543, 687, and 712 through 729, designed to increase the Company's electric retail revenues by $35,460,000, effective January 1, 1986. This amount represents an increase of approximately 3.45 percent in total revenues. The Company's prefiled testimony and exhibits are based on a test year ending June 30, 1985. On December 23, 1985, the Department suspended the rates and charges until July 1, 1986, to allow further investigation into the propriety of the proposed increase. Public hearings were held in Boston on January 28, 1986, and in Framingham on January 29, 1986, to afford interested persons an opportunity to be heard concerning the proposed rates.

BECo is a public utility engaged principally in the generation, purchase, transmission, distribution and sale of electric energy. The Company supplies electricity at retail to an area of approximately 590 square miles within 30 miles of Boston, encompassing the City of Boston and 39 surrounding cities and towns. The population of the territory served at retail is approximately 1,500,000. BECo serves about 554,200 residential customers, 82,400 commercial customers and 1,500 industrial customers. BECo also supplies electricity to other utilities and municipal electric departments at wholesale for resale, and it provides steam to customers in the City of Boston. During calendar year 1985, the Company had residential

sales of electricity of $301,164,886, commercial sales of $547,058,369, and industrial sales of $148,864,148. Street and highway lighting sales amounted to $19,797,030, while special contract sales to railroads and railways amounted to $10,000. The Company's sales for resale during the same period amounted to $126,047,331. Total revenues in 1985 were $1,142,941,764.

The Department last granted a rate increase to the Company in D.P.U. 1720, issued on June 29, 1984. In that Order, based upon a test year of twelve months ending June 30, 1983, the Department granted an increase in gross retail revenues in the amount of $35,221,000. The Department also allowed a return on common equity of 15.25 percent in that case.

Intervention in this proceeding was granted to the Attorney General of the Commonwealth ("Attorney General"), the City of Boston ("City"), the Boston Housing Authority ("BHA"), the Energy Consortium ("Consortium"), Cogeneration Management Corporation, Inc. ("CMC"), Bentley College ("Bentley") and Amstar Corporation ("Amstar"). Stanley U. Robinson, III ("Robinson") was allowed limited-participant, nonparty status. The Commission designated Robert Shapiro, Esq., and Donna C. Sharkey, Esq., as hearing officers for this case.

On December 17, 1985, BECo filed a request for approval of two experimental interruptible rate schedules and six conservation and load management ("C&LM") programs. The Company requested that the Department assess the appropriateness of the

proposed programs and clarify the Department's directions regarding such programs as set forth in D.P.U. 1720. The proposed tariffs were suspended until July 1, 1986, and the filing was docketed as D.P.U. 85-266.

On January 6, 1986, the Attorney General filed a motion to consolidate D.P.U. 85-266 and D.P.U. 85-271. In its response dated January 15, 1986, the Company did not oppose the Attorney General's motion as it related to the proposed interruptible rates. In regard to the proposed C&LM programs, however, the Company requested that the Department authorize the Company to proceed with the six pilot programs before June 30, 1986, or, in the alternative, set forth the cost recovery rules applicable to such programs. On February 13, 1986, the Company filed a motion to transfer all consideration of C&LM issues from D.P.U. 85-271 to D.P.U. 85-266.

On February 21, 1986, the Department granted the Attorney General's motion to consolidate. The Department's action rendered moot the Company's motion to transfer consideration of C&LM issues to D.P.U. 85-266.

On February 26, 1986, the Company filed a motion to expedite the Department's approval of the six C&LM pilot programs. On May 29, 1986, the Department granted the Company's motion to expedite and reiterated the cost-recovery rules applicable to C&LM programs. Boston Edison Company, D.P.U. 85-266/85-271 (1986).

Evidentiary hearings commenced on February 6, 1986, and concluded on April 2, 1986. In all, 27 days of evidentiary

hearings were held. The Company presented seven witnesses in support of its proposed rate increase: Marc S. Alpert, vice president of the Company and head of its Rates Organization (overall cost of service; cost of capital); Richard LaCapra, utility analyst and principal of LaCapra Associates (allocated cost of service study); Robert D. Saunders, manager of the Company's Rate and Load Research Department (rate design); William J. Manion, president of the NES Division of the Nuclear Energy Service (decommissioning costs); G. Robert Faust, independent consultant (depreciation); Zvi Benderly, economist and principal of Benrose Economic Consultants, Inc. (cost of equity capital); and Thomas J. May (Company's financial overview). BECo also made four witnesses available for questioning: Donald Anastasia, manager of benefits and investments; Forrest Carr, head of the Company's Technical Service Division, Transmission and Distribution Department; Richard S. Hahn, manager of supply and demand planning; and Joseph Passagio, tax manager.

Certain intervenors also sponsored witnesses. The Attorney General presented James P. Marquart, utility consultant for Consumer Cost Consultants, Inc. (cost of service), and Susan Geller, utility rate analyst for the Attorney General's office (rate design). The City presented Stephen W. Ruback, utility consultant and principal of The Columbia Group, Inc. (rate structure). The BHA presented David A. Jackson, energy systems specialist for the BHA (energy conservation). Bentley sponsored Robert Lenington, vice president for business and finance of

Bentley College, and Donald E. Johnstone, a consultant with Drazen-Brubaker & Associates, Inc. (G-6 rate).

On April 7, 1986, the hearing officers established a briefing schedule. Pursuant to that schedule, the City, BHA, the Consortium, CMC, Bentley, Amstar and Robinson filed their initial briefs on April 22, 1986. Although the Attorney General was scheduled to submit a brief on April 22, the hearing officers granted a one-day extension and allowed the Attorney General to submit his brief on April 23, 1986. The Company filed its initial brief on May 5, 1986. Intervenors, except for the City, filed reply briefs on May 12, 1986, and the Company filed its reply brief on May 16, 1986. The City filed its reply brief on May 16, 1986. On May 19, 1986, the Company filed a motion to strike the City's reply brief. On May 27, 1986, the City filed its opposition to that motion. On June 2, 1986, the hearing officers denied the Company's motion to strike. On June 11, 1986, the Company filed its reply to the City's reply brief.

In accordance with Department practice, the record in this proceeding was left open to allow for the submission by BECo of updated information. On June 2, 1986, the Company provided the Department with updated data regarding storm expenses, wage and salary expense, property taxes, purchased power and transmission contracts, Pilgrim contract sales revenue, and the inflation factor. On June 12, 1986, the Company provided the Department with a further update regarding wage and salary expense. On June 24, 1986, the Company filed a further update regarding property taxes.

II. THE COMPANY'S FAILURE TO MEET ITS PUBLIC SERVICE OBLIGATION

As we indicate in the following sections, we have grave concerns about the ability and desire of BECo's management to carry out its public service obligation. Based on the evidence in the record of this case and other recent cases involving this Company, we conclude that there is a pervasive attitude within the Company's top management, that unless ratepayers underwrite the business risks associated with the Company's operations, it is not required to act in a manner consistent with its public service obligation.

For example, in a recent request for the Department's approval of a debt refinancing plan, the Company indicated that it would not proceed with the refinancing -- a refinancing that would significantly lower its cost of service -- unless the Department adopted a specific ratemaking approach advocated by the Company. Boston Edison Company, D.P.U. 86-71 (1986). In that case, the Department was forced to conclude:

> We agree with the Attorney General that the Company has an obligation to ensure that it provides reliable service at the lowest cost to ratepayers. In this instance the Company has indicated that it intends to ignore its public service obligation by refusing to reduce its cost of service to ratepayers unless the Department agrees to revise longstanding ratemaking standards applicable to this and other similar expenses. The attitude expressed by the Company in this regard is alarming.
>
> In fulfilling its public service obligation, the Company is required to exercise prudent management judgment and incur substantial expenses necessary to provide reliable service to its customers. If management decides to refrain from making such expenditures because it has not been guaranteed full cost recovery before the fact, then service to ratepayers is placed in jeopardy. The Company's position with regard to this matter indicates a lack of understanding of its public service obligation. D.P.U. 86-71, pp. 15-16.

Similarly, the Company recently indicated that it would not honor a negotiated contract with a cogeneration facility -- a contract the Company asserted was in the best interests of its customers -- unless the Department made explicit findings that all costs associated with that contract would be fully recoverable from ratepayers and that the Company would be held harmless from any management imprudence of the cogenerator. Northeast Energy Associates, D.P.U. 86-91 (1986). The Company's requirement for a ruling on this matter was made by letter halfway through the sixty-day review period of the contract, in a manner that can be characterized most charitably as a "take-it-or-leave-it" offer.[1/] The Department was once again forced to conclude:

> [T]he Department is concerned over representations made in the Company's May 16th letter which indicated that it would not proceed with a contract which it has determined to be beneficial to ratepayers unless the Department stated in advance its position concerning the ratemaking treatment to be accorded this contract. The Department reiterates its position that the Company has an ongoing obligation to provide reliable service at reasonable cost, and that this responsibility rests with BECo's management and not with the Department. D.P.U. 86-91, p. 9.

The Company's recently developed approach to dealing with regulation, as reflected in these cases, represents a significant departure from past practice and would have the effect of transferring all business risk associated with the

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1/ The Department has seen this attitude expressed before by the Company. During testimony concerning the Company's request for an oil conservation adjustment ("OCA") charge to pay for the conversion of the New Boston power plant from oil to coal, Company witnesses likewise indicated that, unless BECo's shareholders were shielded from all risk associated with the construction activity, the Company would not proceed with its plans. Boston Edison Company, D.P.U. 85-58, p. 14 (1985).

Company's operations to its ratepayers. This pattern of cases apparently is not accidental, for on the record of this case are clear statements by managers of the Company concerning their perception that the Company's obligation to serve the public is in question. BECo's president, Stephen J. Sweeney, for example, has concluded that recent regulatory actions have resulted in "the apparent elimination by regulators of the implicit, if not explicit, contract between consumers and utilities.... Under these rules," he suggests, "investors would have no incentive to invest and utilities would lose control of their ability to obtain the funds necessary to meet their public service obligation.... The result is a determination by utility management not to move forward on major construction projects until and unless there is clearer support from regulators as well as other government officials and the public" (Exh. BHA-21).

Based on the record in this case, we conclude that Mr. Sweeney's statements accurately reflect the business policy of the Company's management. As Mr. Alpert testified in this proceeding:

> In general, the Company does not intend to make investments when DPU decisions make it clear that the Company runs an extremely high risk of never recovering the investment cost.... If the DPU has raised questions with specific types of investments as to whether the Company will be allowed to recover the money in the future, then the Company's policy definitely is to seek DPU clarification that prudently incurred costs will be recoverable before the Company makes further investments (Tr. 5, pp. 627-28).

While we disagree with Mr. Sweeney's underlying premise, the implications of the resulting policy decision are clear. The

Company, in an effort to avoid what it perceives as an excessive allocation of risk to its shareholders, apparently intends to refrain from proceeding with major expenditures and investments unless and until it receives assurances as to what ratemaking treatment those expenditures will be given in some future proceeding. We find that, as a direct result of this policy, the Company's management has become paralyzed and has abdicated its managerial responsibilities by requiring regulatory approval before implementing management decisions. In short, management has ceased to manage, in defiance of its public service obligation; an obligation, we must note, whose very existence Mr. Sweeney incorrectly and inappropriately questions.

A symptom of this paralysis has become apparent in this proceeding, where the evidence indicates that the failure of management to manage has permeated the Company's entire capacity expansion planning process. The Company's general approach to capacity planning and investment decisions has resulted in a situation in which "the Company's resource plan is no more concrete than it was during DPU 1720" (Company Brief, p. 255). In that case, decided on June 30, 1984, the Company was projecting the need for additional generating capacity in 1991. D.P.U. 1720, p. 158. Now, two years later, the Company is projecting the need for additional capacity in 1988 (Exh. BE-305, MCWS-101). Thus, in a two-year period, in which the lead time for addressing its need for capacity has been reduced from seven years to two years, the Company has failed to make

progress in solidifying its capacity plans.

This failure is particularly significant in light of our findings in Section V, infra, in which we conclude that the Company has not engaged in a least-cost planning strategy because it has adopted planning criteria which prevent the implementation of cost-effective energy conservation and load management ("C&LM") programs. Such programs could have been designed to delay, in a cost-effective manner, the date additional capacity will be needed. We find in this Order that this failure has resulted in a cost of service higher than would exist had the Company made a true commitment to reasonable C&LM measures.

We recognize the significant level of uncertainty associated with utility planning decisions, but this uncertainty cannot be used to justify institutional paralysis. The electric utility industry is changing, not as a result of regulation, but as a direct result of economic and technological forces. Management must recognize and respond appropriately to these changes. In contrast, BECo's management persists in ignoring fundamental changes in the industry, instead finding it more convenient to blame the shortcomings of regulation for Company problems and rationalizing the transfer of management responsibilities to the Department.

BECo misconstrues the ratemaking process by placing an emphasis on cost recovery. Rates are set on a prospective basis, relying on historical experience as an indication of what

is most likely to occur in the future. If the Department, in deciding rate case issues, imposes or applies a standard which illegally deprives the Company of a property right or an opportunity to earn a fair return, the Company has the right to appeal that decision to the Supreme Judical Court. G.L. c. 25, sec. 5. Through this process the Company's rights are adequately protected. For the Company to reject this process, and respond with a policy of disregarding its public service obligation, is to show disdain for the public trust with which it has been vested.

The ratemaking process does not carry with it guarantees of financial success for a utility. Commonwealth Electric Company v. Department of Public Utilities, 397 Mass. 361, 368 (1986). Rather, it is designed to provide an opportunity for a company to earn a fair rate of return. Eastern Edison Company, D.P.U. 1580, p. 104 (1984). It is the job of the officers and managers of the Company to carry out its public service obligation in a manner satisfactory to both the public and Company shareholders. It is not the job of the Department to make management decisions on behalf of the Company's managers.[2/]

2/ In extreme cases, the Department has found it necessary to exercise its general supervisory authority under G.L. c. 164, sec. 76, to ensure that management decisions are carried out in a manner consistent with the public interest. See, for example, Commonwealth Electric Company, D.P.U. 84-114 (1985) (billing and termination procedures); Eastern Edison Company, D.P.U. 85-232 (1986) (preparation for natural disasters); Boston Edison Company, D.P.U. 19494 (1981) (major capacity planning decisions). We view these cases, however, as unavoidable exceptions to our general desire to let the management of a utility carry out its responsibilities.

On the issue of potential investment in new facilities, for example, we find disingenuous the Company's contention that its lack of direction results from regulatory changes. With respect to that planning process, the Company has simply failed to develop such plans. Meanwhile, the Company's planning horizon is disappearing as its management stands idle, content to blame regulation for whatever consequences may result from its failure to take action. If the Company continues to combine an abdication of its responsibility for capacity expansion planning with an approach that undervalues the potential for C&LM programs, it will jeopardize the health and safety of its customers and the economy of the region. The Company's apparently cavalier attitude toward these impending consequences is a development which we regard with extreme alarm.

The Department has for years attempted to work with the management of the Company to reach agreement on what constitutes prudent utility practice in times of extreme uncertainty. We have enjoyed little success in this process and are now confronted with a Company policy of avoiding important decisions which may have a business risk attached to them. The Company's implementation of such a policy is especially curious at this particular time, given what can only be viewed as its significantly improved and robust financial performance in recent years. For example, according to the Company's 1985 Annual Report to its shareholders:

- o Return on average equity has risen dramatically from 10.02 percent in 1982 to 14.54 percent in 1985;
- o Fixed-charge coverage ratios have risen from 2.28x to 3.01x during the same period;
- o The stock price has risen from a range of $25-$29.50 to $33.63-$46.25;
- o The market-book ratio has risen from .82 to 1.30.

These improvements belie the Company's contention that regulatory changes have unduly shifted business risk to shareholders. Certainly the Company's performance in financial markets does not support Mr. Sweeney's conclusions. Shareholders do, however, bear the risks associated with poor management; but the response should be an improvement in management, not the abdication of management responsibility through a transfer of that responsibility to this agency.

In the Company's 1978 rate case, the Department stated:

> Efficient and economical management is a seldom-discussed but crucial requirement of the regulatory process. That such management may be lacking in this Company has been a matter of great concern to the Commission, dating back at least as far as July of 1974. Boston Edison Company, D.P.U. 19300, p. 79 (1978).

We must reluctantly conclude that the systemic mismanagement problem discussed by our predecessors eight years ago still exists. We fear that further delays in addressing this issue will simply provide the Company with a signal that all is well. But all is not well.

We are thus left to decide how to address this issue in this rate case. We perceive three appropriate actions that we can take within our statutory authority.

First, we have concluded that it is appropriate to grant the Company an allowed return on equity at the lower limit of the range we have found reasonable. See Section VII, infra. We believe it is lawful and appropriate to take this action in light of the Company's failure to address adequately its public service obligations. In fact, declining to take this action would fail to send a signal to the shareholders of the Company that its managers have not performed their tasks in a manner that is consistent with the public interest.

It is clear that the management of the Company does not believe it is accountable to either its customers or the Department. It is therefore appropriate to send a strong indication to those responsible for selecting the current management team that disregard of the Company's public service obligation will not be condoned or tolerated.

Second, we have excluded for ratemaking purposes $927,000 in expenses associated with the Company's Senior Management Incentive Compensation Program. See Section IV.V.3, infra. We find it unconscionable to require ratepayers to pay a bonus for inadequate management. The Department was forced to take a similar action in 1978 in the face of the above-mentioned concerns about the Company's management. D.P.U. 19300, pp. 31, 79-90.

Finally, we wish to be assured that the contents of this Order are presented to the Board of Directors of the Company. Accordingly, simultaneously with its being made available to the

parties in the case, copies of this Order will be delivered to the outside directors of the firm.

We do not take these actions lightly and we regret having been placed in the position of doing so.[3/] BECo is a major utility in the Commonwealth, and its performance has significant consequences for the economy of the region. We have hoped, and continue to hope, that the Company would be managed in a manner warranting pride in its performance by employees, regulators and the citizens of the Commonwealth.

3/ In taking these actions, we acknowledge an area in which the Company's performance has been exemplary. As we find in Section VII, *infra*, BECo has been a leader among utilities which have come before the Department in the area of rate structure, and we have recognized that exceptional performance in the allowed rate of return decided in this case.

III. RATE BASE

A. Pilgrim Common Facilities

In 1971, BECo initiated plans to build a second nuclear power plant in Plymouth, Massachusetts. The planned 1,150 megawatt ("MW") plant, designated Pilgrim 2, was to be owned by several utilities. BECo was the lead participant, with an ownership share of approximately 59 percent. Financial considerations led BECo's board of directors to vote to cancel the project on September 23, 1981. Boston Edison Company, D.P.U. 906, p. 155 (1982).

BECo executed an agreement ("Reconveyance Agreement") with the joint owners of Pilgrim 2 for the repurchase by the Company of the other joint owners' interests in the cancelled unit's site, site improvements, common facilities and accompanying easements ("common facilities"). The sale and purchase in accordance with the terms of the Reconveyance Agreement was approved by the Department in D.P.U. 84-47 (1985). The Federal Energy Regulatory Commission ("FERC") approved the repurchase of the joint owners' interest in those common facilities deemed to be transmission-related in its orders in Docket No. EC84-15-000, issued August 31, 1984, and Docket No. ER84-525-000, issued December 14, 1984. The record in D.P.U. 84-47 was incorporated by reference into the record in this docket. In D.P.U. 84-47, the Department made no explicit findings regarding the rate treatment to be afforded the reconveyed property, reserving consideration of that issue to future rate proceedings. D.P.U. 84-47, p. 5.

In the Company's last two rate proceedings, BECo has proposed the inclusion of Pilgrim common facilities in rate base. In both D.P.U. 1350 and D.P.U. 1720, the Department rejected the Company's proposal. Noting that the sale was not consummated and requisite regulatory approvals had not been granted, the Department stated that the proposed addition failed to meet the Department's known and measurable standard. In addition, the Department required that the Company demonstrate that the common facilities are appropriately allocable to Pilgrim 1 before including any portion of those facilities in rate base. Boston Edison Company, D.P.U. 1720, p. 17 (1984).

1. Common Facilities Repurchase

The Company has renewed its request to include the repurchased facilities in rate base in this proceeding. The Company proposes to record those assets on its books at the net original cost of $7,078,000, which is $1,274,000 less than the repurchase price of $8,352,000 for twelve of the thirteen joint owners' ownership shares. The Company has allocated a portion of the cost of repurchasing the common facilities to the Pilgrim unit contract customers (Exh. BE-100, p. 81).

The Company has not completed the repurchase from all of the joint owners. On September 12, 1985, BECo closed with eleven of the thirteen joint owners in the Pilgrim 2 project. The total net payment of $6,726,255.85 included amounts for the repurchase of the unit site and common facilities as well as costs for the transmission line and interest payments due under the

Reconveyance Agreement. On November 14, 1985, BECo closed with an additional joint owner at a net price of $549,700.95 (Exh. BE-114). Vermont Electric Cooperative's 0.2 percent share has not yet been repurchased, nor has a final closing date been scheduled. The Company estimates that approximately $28,430.64 must be paid to the remaining joint owner at some future date (Exh. AG-99).

The Attorney General has not taken a position on the Company's proposal to include the repurchased facilities in rate base, except to advocate that the reacquisition cannot be included at any amounts above the $7,078,000 net original cost for the Pilgrim common facilities (Attorney General Brief, pp. 36-39).

The Company has allocated all costs of the common facilities to the Pilgrim 1 unit, asserting that all portions of those facilities are both useful and necessary for the continued operation of that unit. To support that contention, the Company offered examples in a seven-page memorandum to indicate that, for the four categories of facilities, i.e., (1) the unit site; (2) the site development; (3) the common facilities; and (4) the balance of the station site, the Company was using all the facilities for Pilgrim 1. The Company has used the common areas to construct an administrative support services building, parking areas and a gas bottle storage area; BECo plans additional construction for trash compaction facilities (Exh. BE-114, p. 3).

The Department finds that the Company's proposal to include the common facilities in rate base at the net original cost of $7,078,000 is appropriate. The payment to the joint owners above the net original cost is not eligible for inclusion, nor has the Company proposed to include it in the rate base or in its cost of service. The Company has stated its intention to include the premium in the report updating the Pilgrim 2 cancellation costs prepared by independent auditors which the Company must file in conformance with D.P.U. 906 by April 1987. We concur with that treatment of those costs, since they are akin to net salvage and other cancellation costs related to Pilgrim 2.

2. Pilgrim 2 Rental/Interest Charges

The Company has requested a three-year amortization of $1,344,000 in rent/interest charges associated with the repurchase of the Pilgrim common facilities. BECo characterizes the amounts as rental charges due to the joint owners for use of the facilities pending their reconveyance. The adjustment would increase test year cost of service by $448,000[4/] (Exh. BE-100, p. 52; Exh. BE-101, p. 8, l. 27).

4/ We note that, in discussing expenses incurred by the Company, we will generally refer to the total amount expended, although the amount reflected in retail rates may be somewhat lower because of the allocation of most costs between wholesale and retail sales. We will generally not distinguish between wholesale and retail costs in the body of the Order and any allocation will be indicated on Schedule 16, *infra*, consistent with the Company's allocations unless otherwise indicated.

The repurchase agreement required monthly payments for the use of the unit site by the Company before reconveyance. BECo was responsible to make "monthly payment in the form of rent for the use of the said Unit Site" to each joint owner if reconveyance was delayed beyond November 1, 1983 (Exh. HO-111, p. 6). The amounts were accrued on a monthly basis by applying the weighted average interest rate of 90-day Treasury bills to each joint owner's investment share in the unit site. The payments relating to these charges were made to the joint owners in addition to the $8,325,000 repurchase price at the time of the reconveyance (Exh. HO-103).[5/] No monthly rental payments were made before that time.

The Company states that the rental provision was included because the Company required use of the site but anticipated a delay before the reconveyance was completed. BECo asserts that regulatory approvals took much longer than anticipated (Exh. BE-120, p. 16).

The Attorney General argues that the rental/interest charges are nonrecurring. Also, arguing that the costs were unnecessary under the original joint ownership agreement and therefore imprudent, he requests that the amounts be excluded from cost of service. Alternatively, the Attorney General characterizes the charges as acquisition costs which should not be expensed and which cannot be capitalized without special permission.

5/ At the time of the closings, the net payment by the Company consisted of the unit site and common facilities amount less the amount due to the Company for each joint owner's share of the Pilgrim 2, 345 kilovolt transmission line plus the interest/rental payment amount (Exh. AG-99).

The Company asserts that the charges were paid to obtain the right to use necessary facilities before the actual transfer of ownership, in order to protect the Company's operations at Pilgrim 1. Agreeing that the expense is nonrecurring, the Company points to the Department's established precedent of amortizing extraordinary, nonrecurring expenses.

BECo also challenges the Attorney General's characterization of the charges as acquisition costs, stating that the rental payments have no connection with the acquisition price.

We find that the rental payments are inextricably connected with the acquisition costs. This expense item was incurred solely because of the reacquisition of the Pilgrim common facilities. The Reconveyance Agreement approved by the Department in D.P.U. 84-47 required the payment of the rental charges under paragraph 4 (Exh. HO-11, p. 6). Accordingly, we find that these charges should be included in the calculation of Pilgrim 2 cancellation costs and reviewed by the Department in its consideration of the audited Pilgrim 2 cancellation cost report. The Company's request to amortize the charges is therefore denied, and $448,000 is removed from the proposed cost of service.

B. <u>AFUDC Relating to 1984 Pilgrim Outage</u>

BECo's Pilgrim 1 nuclear unit was shut down from December 10, 1983, to December 30, 1984. The extended outage included both work related to a normal refueling outage and a forced outage to make repairs ordered by the Nuclear Regulatory

Commission ("NRC"). The Company accrued allowance for funds used during construction ("AFUDC") on both nuclear fuel and nonfuel-related outage expenses during this period. AFUDC is an accounting and ratemaking convention which allows companies to recover the costs of financing a construction project by capitalizing the carrying charges associated with financing the project during construction and including those costs or a part of plant in service in rate base. Once the project is completed and becomes used and useful in providing service to ratepayers. In this case, nonfuel AFUDC associated with capitalized outage plant repairs and additions has been included in the Company's calculation of rate base (Exh. AG-69).

The Attorney General argues that BECo should not be allowed to accrue AFUDC on outage expenses unless Pilgrim 1 plant accounts are removed from rate base for the period during the outage. "Since Pilgrim I is a completed and operating asset that is used and useful, the costs of that asset are reflected in the nuclear plant accounts in Electric Plant in Service - Account 101 and not in Construction Work in Progress" (Attorney General Brief, p. 5). The Attorney General points to accounting standards adopted by the FERC which state that AFUDC should not be accrued on completed plants. He requests that the $8.9 million in AFUDC capitalized during the outage be excluded from the Company's rate base.

The Company accrued AFUDC on those capital items added to plant during the outage which were not yet in service (Company

Brief, p. 40). BECo argues that this practice is in accordance with the Uniform System of Accounts, standard regulatory practice and past Company rate cases (id.).

The Attorney General's proposal, taken to its logical conclusion, would prevent companies from accruing carrying charges on any item smaller than a generating unit, necessitating the removal and replacement of units from rate base during outages for repairs. That proposal is not consistent with existing Department practice, would serve no useful purpose, and would not be administratively and financially feasible. The Company incurs financing costs on capitalizable plant additions before they become eligible for inclusion in rate base. It is, therefore, appropriate and consistent with Department practice to accrue AFUDC on such capitalizable additions before they becoming used and useful as plant in service. Accordingly, we find that the adjustment to the Company's rate base proposed by the Attorney General is inappropriate.

C. Cash Working Capital Allowance

The Company in its day-to-day operations requires working capital to meet its cash requirements for providing service pending receipt of associated revenues. Working capital is provided either from funds internally generated by the Company or from short-term borrowings. The Company is entitled to be reimbursed for the costs associated with the use of its funds or for the interest expense it incurs on such borrowings. This

reimbursement is accomplished by adding a working capital component to the rate base computation.

BECo included a cash working capital allowance of $78,175,000 in its rate base calculation (Exh. BE-101, p. 51). This amount consists of $45,290,000 to cover a 45-day cash requirement for operation and maintenance ("O&M") expenses and $32,886,000 to cover a 30-day cash requirement for fuel and purchased power expenses.

The O&M portion of the working capital allowance was derived by applying the 45/365 convention to net O&M expenses. In the absence of a lead-lag study, the Department generally has relied on the 45-day convention as being reasonably representative of a company's working capital requirements for ordinary O&M expenses. See <u>AT&T Communications of New England</u>, D.P.U. 85-137, p. 22 (1985); <u>Boston Edison Company</u>, D.P.U. 1720, p. 11 (1984). No party disputed the Company's proposed adjustment. The Company's filing conforms to the Department's standards. Therefore, the Company's cash working capital requirement for O&M expenses is allowed.

The Company's cash working capital requirement for fuel and purchased power was calculated by multiplying normalized test year fuel and purchased power expenses by 30/365. In D.P.U. 1720, the Department found the 30-day requirement was appropriate to apply to the Company's purchased power expenses based on a lead-lag study submitted by the Company and reviewed by the Department in that proceeding. On the basis of our

finding in that case and in the absence of evidence that circumstances have changed since that time, we will accept the use of the 30-day calculation for both fuel and purchased power expense in this proceeding.

Normalized fuel and purchased power clause expenses were calculated by a production cost model which simulates a normalized dispatch of the Company's system. The calculation uses a normalized generation mix and test year average fuel prices, consistent with Department precedent. Western Massachusetts Electric Company, D.P.U. 957, p. 38 (1982).

The Attorney General and the City have opposed the fuel and purchased power component of the Company's proposed cash working capital allowance. Both parties assert that the Company's fuel and purchased power component is overstated.

The Attorney General proposes that the Company's normalized fuel and purchased power cost calculations incorporate the use of different generating unit performance statistics. Instead of the normalized dispatch assumptions used by the Company in the production cost simulation model, the Attorney General argues that the performance statistics adopted by the Department in BECo's latest annual performance program goal-setting proceeding and used by the Company in its embedded cost of service study for rate design purposes, should also be used to normalize BECo's generation mix and fuel and purchased power costs for working capital purposes. The Attorney General estimates that the use of performance program characteristics reduces the

working capital requirement for fuel and purchased power costs to $29,971,000 (AG-RR-34).

In addition to the use of performance program criteria, the Attorney General and the City propose that more recent fuel prices which recognize the recent drop in oil prices, rather than average test year fuel prices, be incorporated into the calculation of normalized fuel and purchased power costs. The City argues that forecasted fuel costs are more representative of costs that the Company will incur in the future. Acknowledging that the Department has rejected the use of post-test year fuel prices in the past without a demonstration that those prices are more representative than test year prices, the City argues that the degree of change in oil prices recently experienced demonstrates that the most recent oil price forecasts are more representative of what is likely to occur in the future (City Brief, pp. 29-30). The Attorney General agrees that forecasted fuel prices should be used in calculating working capital (Attorney General Brief, pp. 8-9).

The Company argues that the use of the generating unit performance goals would be inappropriate in developing a representative level of fuel and purchased power expense since the goals are set at a level which, although reasonably attainable, represents the most optimal level of performance. "The Department manifestly does not attempt to design goals so that they will equal the Company's actual unit operation in the performance year. The Department by design sets goals at an

extremely high, challenging level" (Company Brief, pp. 45-46). The Company states that, since reasonable variations from the goals do not subject a company to a penalty unless the Department finds the failure to meet a goal results from some imprudent activity, the goals are not an appropriate tool for forecasting unit performance (id., p. 56).

In adjusting test year fuel and purchased power costs, the Department requires companies to normalize actual test year dispatch, so as to smooth out any abnormalities peculiar to the test year and to represent better the mix of purchased power and company generation in the future. Our review of the proposal to use performance goals to normalize test year data must consider the function of the performance goals and the manner in which the Department sets such goals.

The function of the performance goals is to define the optimal level of generating unit performance for individual companies and to assess each company's actual performance against that standard. Chapter 375 of the Acts of 1981, codified at G.L. c. 164, sec. 94G, in defining the performance program, states:

> Any such program may specify a value or a range of values for the operating characteristic in question and shall reflect operating conditions when overall performance is optimized....
>
> Each such electric company shall file with the department, with the frequency and in the standardized form established by the department, data and reports on the actual unit by unit and system performance of the company with respect to each target set forth in the approved performance program.

The Department has recognized that the optimal performance defined by the goals may not be achieved by companies in subsequent actual unit performance and that the failure of companies to meet those goals may not reflect imprudent behavior.

> If goals are set too high for a company's units to achieve, there is no automatic penalty.... However, failure to meet such goals can be explained by a company and as the Attorney General has noted, the Act specifically includes provisions for a company to explain variances from goals. Therefore, the expectation is that companies could fail to meet reasonably attainable goals without being judged imprudent.... When such an explanation is adequate, no penalty will be imposed and no stigma will attach. Therefore, if the Department sets goals at the highest reasonable level of performance for each unit, the Company incurs no automatic penalty for failure to meet the goal, the investment required to achieve the goal is identified and reviewed for cost-effectiveness, performance is encouraged to improve, the ratepayers benefit from improved generating efficiency, and the public interest is served. Boston Edison Company, D.P.U. 84-274, pp. 31-32 (1985).

Since the goals are set at the highest reasonable level of performance for each unit, the use of the goals rather than the Company's assumptions of availability of various units may not produce an accurate projection of the Company's generation mix and resulting fuel and purchased power expense for the period during which proposed rates will be effective. Therefore, we accept the use of the Company's assumptions of unit availability in normalizing test year dispatch.

The Department will use test year average prices in calculating the fuel and purchased power component of the Company's cash working capital allowance. As the City notes,

the Department has rejected the use of post-test year or spot oil prices when those prices have not been found to be representative. See Boston Edison Company, D.P.U. 1350, pp. 27-29 (1983); Western Massachusetts Electric Company, D.P.U. 1300, pp. 28-29 (1983). In making those findings, the Department determined that price volatility in world oil markets created uncertainty which precluded a finding that those proxies were more representative than average test year prices. Statements regarding the expected magnitude of projected decreases in oil prices do not demonstrate that the forecasted prices are more representative of oil prices which may be experienced during the period that proposed rates will be effective, or that they constitute a known and measurable change for which expenses should be adjusted. We find that, absent a showing that an alternative method is more representative of actual oil prices which will be experienced during the period in which rates set in this proceeding will be effective, we will continue to use average test year prices in normalizing the fuel and purchased power component of cash working capital. Accordingly, we do not adopt the intervenors' proposed adjustments to the Company's calculation of its cash working capital allowance.

D. Pre-April 7, 1983 SNFDC

On June 28, 1985, pursuant to the Department's decision in Boston Edison Company, D.P.U. 84-1B (1984), the Company made a $40,583,000 payment to the Department of Energy ("DOE") for

pre-April 7, 1983 spent nuclear fuel disposal costs ("SNFDC"). SNFDC are what each utility having a nuclear power plant pays to have the spent fuel, which is still radioactive, disposed of under procedures approved by the federal government.

The Company presently recovers its DOE payment from its ratepayers through the fuel clause at a rate of $241,462 per month (Exh. AG-120, pp. 1-2). In Boston Edison Company, D.P.U. 85-1C (1985), the Department authorized the Company to collect an additional amount through the fuel charge for financing costs necessary to carry the SNFDC balance. As of June 30, 1985, the Company had collected $24,453,000 for pre-April 7, 1983 SNFDC through the fuel clause (Exh. BE-101, p. 49; Exh. AG-120).

In this filing, the Company has included $40,583,000 in rate base representing its June 28, 1985 payment to the DOE (id.). At the same time, the Company has reduced rate base by $24,453,000 for amounts already recovered from ratepayers for SNFDC through the fuel clause as of June 30, 1985 (Exh. BE-101, p. 49). The Company's proposal to include in rate base the unreimbursed portion of its payment to DOE would obviate the need to recover financing charges through the fuel clause.

The Attorney General notes that the Company, since the end of the test year, has continued to collect $241,462 per month through the fuel clause and will have collected an additional $2,656,082 over the period July 1, 1985, through May 31, 1986 (Exh. AG-120). The Attorney General argues that, if the Department allows the Company to collect finance charges through

rate base, then $2,656,082 should be removed from rate base to prevent a double recovery of interest (Attorney General Brief, p. 10).

The Company agrees with the Attorney General's proposal and states that, once the net SNFDC investment is in rate base, it will terminate collection of financing costs through the fuel clause (Company Brief, p. 48).

The Department agrees that the Company should no longer collect financing costs associated with the SNFDC payment through its fuel clause. The Department also finds that, in order to prevent a double recovery of financing charges, the $40,583,000 SNFDC payment in rate base should be offset by the amount recovered through the fuel charge as of June 30, 1986, the date when collection of financing charges through the fuel clause will terminate. Accordingly, nuclear fuel in rate base is reduced by $2,897,544, representing funds collected through the fuel clause between July 1, 1985, and June 30, 1986.

E. Sales of Utility Property

1. Kingston Street Property

On March 20, 1986, the Company received a $3,617,451 settlement from the City of Boston as the result of an eminent domain proceeding (City-RR-15). The eminent domain proceeding involved the taking of a parcel of land which was a portion of the Company's Kingston Street Station 514 (City-RR-14). The Company's cost of service witness testified that the payment of March 20, 1986, was booked to Account 421, a below-the-line account for miscellaneous nonoperating income (Tr. 25, p. 3326).

The City notes that the subject land is included in the Company's rate base (City-RR-14) and argues that shareholders have received the benefit of the settlement amount while ratepayers continue to pay a return on the subject property. The City recommends that cost of service be reduced by $3,617,451 (City Brief, pp. 25-26).

The Company notes that the original cost of the subject property in 1972 was $1,334,413, which has been included in rate base (Exh. AG-185; City-RR-15-Revised).[6/] It states that, although the gain on the disposition of the property was recorded in miscellaneous nonoperating income, this entry was made only for FERC purposes. The Company indicates that when an annual return is filed with the Department, this gain will be accorded above-the-line treatment (Company Brief, pp. 49-50).

Although the Company argues that the sale should be treated as an above-the-line transaction, it disagrees with the City as to the timing of the credit and the amount of the sale that should be credited to ratepayers. On the first issue, BECo argues that the City has not addressed whether the settlement is large enough to warrant an adjustment for post-test year revenues received. The Company asserts that if such a nonrecurring sale of property is large enough to require a post-test year adjustment, then proceeds from the sale should be amortized over a period of years. The Company then concludes

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6/ Because the subject property is land, depreciation expense has not been charged to the property.

that any such amortization should begin with its next rate case (Company Brief, p. 50).

The Company also contends that the City is incorrect in proposing that the total amount of the proceeds of the sale be credited against cost of service. The Company argues that the original cost of $1,334,413 should not be credited, but concedes that this amount should be deducted from rate base in this case. The Company argues that $1,417,451 of the settlement represents interest which it claims is a below-the-line item. According to the Company, only the net gain of $865,587 should be amortized in the Company's next rate case (Company Brief, pp. 50-51).

The Department has held that the net proceeds from the nonrecurring sale of property should be amortized over a period of years. Colonial Gas Company, D.P.U. 84-94, pp. 20-21 (1984); Massachusetts Electric Company, D.P.U. 1133, p. 34 (1982). In Colonial Gas Company, the Department approved an agreement between the company and the Attorney General, allowing the three-year amortization of the proceeds from a post-test year property sale. In Massachusetts Electric Company, the Department ordered the three-year amortization of a gain on property.

The Department finds that the gain realized by the Company through the Kingston Street settlement should be reflected as an adjustment to cost of service in this proceeding. The ratepayers have been paying a return on this property since

1972, and they are entitled to have the impact of the sale of utility property reflected in rates. In this case, we find that a three-year amortization of the settlement proceeds is warranted.

The Department agrees with the Company that the amount credited to the ratepayers should be reduced by the original cost of the subject property, $1,334,000. That amount should also be removed from rate base.

The Department, however, rejects the Company's contention that the interest portion of the settlement should be treated below the line for ratemaking purposes. The ratepayers are entitled to the benefit of all proceeds from a sale of this type, since the asset was utility property included in rate base from the time of its purchase. Accordingly, we find that the cost of service should be reduced by $761,000, representing the three-year amortization of proceeds of $2,283,000.

2. Miscellaneous Property

The Company sold various utility property during the test year. Although the Company's initial filing did not account for the net gain on these property sales in cost of service, the Company noted in its brief that it had realized a $407,365 net gain on properties sold during the test year. This net gain was the result of $865,520 in gains from the sale of property and $458,155 in property losses. The Company proposes to amortize the net gain, $407,365, over five years as a credit to cost of service of $81,475.

The Department finds that a five-year amortization period is excessive, given the magnitude of the net gain, and reduces it to three years. Accordingly, the Company's cost of service shall be reduced by $136,000 to reflect the three-year amortization of the net gain on property sold during the test year.

In sum, we find that rate base shall be reduced by $1,334,000 and cost of service shall be reduced by $897,000 ($761,000 plus $136,000) to reflect test year and post-test year sales of property.

IV. COST OF SERVICE

A. Purchased Power Expense and Transfer to Base Rates

Test year fuel and purchased power expenses were normalized consistent with the standard for the fuel and purchased power component of cash working capital. See Section III. C, supra. Normalized fuel and purchased power expenses were calculated by a production cost model which simulated a normalized dispatch of the Company's system. The calculation used a normalized generation mix and test year average fuel prices.

The Company has included capacity-related charges and revenues in its base rate calculations in compliance with D.P.U. 1720, pp. 59-70. Energy-related expenses are collected through the fuel charge. The Company has included several post-test year adjustments in its calculation of the capacity portion of purchased power expenses collected through base rates. Capacity charges for the Coleson Cove power contract with Maine Electric Company were removed appropriately because the contract has expired. The Company added to its fuel and purchased power expense two additional charges relating to contracts for power from New Brunswick Electric Power Commission's ("NBEPC") Pt. Lepreau generating unit and a combustion turbine unit owned by the Massachusetts Bay Transportation Authority ("MBTA").

1. Pt. Lepreau Performance Charge

In 1981, the Company contracted with NBEPC to receive power from NBEPC's Pt. Lepreau generating unit. The contract included a provision requiring the payment of a performance charge to

begin in February 1986. For each one percent increase in the annual unit capacity factor over 80 percent, the Company must pay a performance charge of two percent of the monthly capacity and energy charges, with a maximum percentage ceiling of 10 percent. The performance charge is billed on a forecast annual basis. If the actual plant capacity factor is determined to be higher or lower than projected, NBEPC will adjust the charge in subsequent monthly billings. The Company has estimated the charge to be $3,819,000, which represents approximately 10 percent of the total $38,192,000 of Pt. Lepreau contract charges during the test year. In subsequent filings, the Company has updated its estimate of the performance charge to $3,887,000.

Although BECo included the performance charge in its calculation of base rates, the Company had requested permission from the Department in this proceeding and in D.P.U. 86-1A-B to collect costs associated with this charge through the fuel adjustment clause (Exh. BE-100, p. 41; Exh. BE-101, pp. 25-26). In D.P.U. 86-1A-B, the Department deferred the decision on the treatment of this charge to this proceeding, but stated that the information provided by the Company indicated that the charge appeared to be a capacity charge consistent with Department precedent since it recognizes the additional reliability of the capacity that BECo purchases from Pt. Lepreau. D.P.U. 86-1A-B, p. 6.

The Attorney General agrees with the Company that the charge should be collected through the fuel clause. The City maintains

that the performance charge is not a known and measurable post-test year adjustment since the amount may vary based on the capacity factor achieved by the Pt. Lepreau unit.

The Company has requested that the Department clarify its Order in D.P.U. 86-1A-B regarding the performance charge (Company Brief, pp. 102-103). The Company maintains that the charge is not a capacity charge, but instead represents an energy charge since it is directly dependent on the amount of energy received from the unit. The Company also asserts that the performance charge cannot be reasonably forecast, but may fluctuate on an annual or monthly basis. The Company asserts that, to avoid uncertainty in ratesetting and the possibility of under- or over-collections, the charge should be included in the fuel clause, rather than base rates.

It is clear from the record that the performance charge is a percentage surcharge on all other charges associated with the Pt. Lepreau contract, the majority of which are capacity-related. Under the terms of the contract, NBEPC will forecast the charge on an annual basis and reconcile on an annual basis once the actual capacity factor for the last year is known (Exh. AG-53). The Company expects that the capacity factor for the unit will be at or above 85 percent based on the actual capacity factor through January 1986 and the planned outage period of April 25 through May 16, 1986. BECo can therefore expect to incur the maximum 10 percent surcharge on all its other Pt. Lepreau charges, although the precise amount of the charge will fluctuate with the sum of all other charges.

Since the charge varies directly with the unit's capacity factor and the amount of the charge is primarily dependent on the level of capacity charges, the effect of the charge is to reflect the varying amounts of additional capacity that the unit will provide to meet the Company's requirements. Accordingly, we find that the Pt. Lepreau performance charge is predominantly capacity-related and should be included in base rates. Accordingly, the updated charge of $3,887,000 will be included in the purchased power capacity expense in the Company's cost of service.

2. MBTA Contract

The Company has included $832,000 in estimated payments to the MBTA for the purchase of 37,800 kilowatts ("KW") from the MBTA's combustion turbine unit in South Boston. The $832,000 represents the minimum annual capacity charge under a proposed life-of-the-unit contract. The Company had not yet finalized the contract with the MBTA during the course of these proceedings. The proposed contract provides for a capacity charge which is currently set as the greater of $22 per KW year or 90 percent of the New England Power Pool ("NEPOOL") Capability Responsibility Adjustment Charge, up to a maximum of $63 per KW year, times the qualified capacity of the facility (37,800 KW). Thus, the Company submits that the minimum annual charge would be 37,800 KW times $22 per KW year or $831,600 (Exh. BE-106, p. 7).

The Company has included this amount in base rates and proposes that any increase in the final capacity charge level over the $831,600 estimate be adjusted for in the fuel adjustment clause (Exh. BE-100, pp. 40-41).

The City argues that the expense is not known and measurable given the uncertainty relating to the plant's audited capacity value as well as the level of the capacity charge.

On June 19, 1986, the Company submitted the finalized version of the contract as a late-filed exhibit. The capacity available to the Company was reduced to 35.5 KW with a corresponding reduction in the capacity charge to $781,000 per year. The submission of the finalized document has come too late in the course of these proceedings to be adequately reviewed by the parties or the Department in this case. Absent an adequate record, we find that expenses relating to the proposed contract with the MBTA have not been shown to be known or measurable. Accordingly, the $832,000 adjustment to cost of service proposed by the Company is denied.[7]

3. <u>Hydro Quebec Transmission Expenses</u>

The Company has included $6,860,000 in its cost of service for post-test year expenses associated with the transmission of electric power from Hydro Quebec, a Canadian utility (Exh. BE-100, pp. 44-45; Exh. BE-101, p. 26). According to Mr. Alpert's testimony, NEPOOL reached an agreement with Hydro

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7/ The Company may include any charges associated with the contract for review in future fuel clause proceedings.

Quebec to purchase 33 million megawatthours ("MWH") of energy over an eleven-year period. The Department approved the interconnection agreements among BECo, Hydro Quebec, NEPOOL and other utilities in D.P.U. 1204 (1982).

The support charges relate to the Company's 11.87 percent share of the construction, operation, maintenance and capital costs of a new 690 MW transmission line. The Company expects this power transmission to begin in the middle of 1986. The Company bases its support charge costs on an estimate by New England Electric Transmission ("NEET"), which, along with Vermont Electric Transmission Company, is constructing the transmission line (Exh. BE-100, p. 45). NEET estimates that BECo's support charges for the six-month period beginning July 1, 1986, will amount to $3,430,000 (Exh. BE-106, p. 6).

The Attorney General's witness, Mr. Marquart, testified that the Hydro Quebec transmission expense estimate of $6,860,000 should be removed from cost of service. Mr. Marquart contended that the support charges fail to meet the Department's known and measurable criterion for a prospective ratemaking adjustment. He noted that the Company has yet to make any support charge payments and pointed to Mr. Alpert's testimony that payments should begin in "mid-1986" (Tr. 4, p. 512) as evidence of the uncertainty concerning when the transmission line will be operational. Arguing that the Company's support charges will depend upon its energy needs (Tr. 4, p. 514), Mr. Marquart recommended that BECo recover its transmission expenses through the fuel clause. In his brief, the Attorney General suggests

that base rate treatment of these expenses be allowed only after further exploration of the transaction in a future rate case (Attorney General Brief, p. 29).

The City also argues that the costs associated with the Hydro Quebec transmission lines remain too uncertain to be included in the Company's cost of service (City Brief, p. 39).

The Company counters that transmission line support charges are not reduced because fewer KWH are required or sent. Instead, Mr. Alpert argued that the NEET contract calls for monthly payments based on the facility's cost, and that payments become due each month once initial service commences (Exh. BE-120, p. 10). The Company further asserts that the support charges do not vary based on the number of KWH transmitted from Hydro Quebec (Company Brief, p. 108).

Although the Company maintains that it has included the support charges in base rates in accordance with the Department's treatment of wholesale power contracts in D.P.U. 1720, it has no objection to including the charges in the fuel charge, along with associated savings, as suggested by the Attorney General (Company Brief, pp. 107-108).

The Company's original proposal to include Hydro Quebec support charges of $6.9 million in its cost of service is inappropriate. The Company has failed to show that the expense is both known and measurable, as required by Department precedent. When questioned as to when BECo's support payments would begin, the Company's cost of service witness could offer

no date more certain than "mid-July, 1986" (Tr. 4, p. 512). Similarly, the Company's calculation of the support charge is based on an estimate from NEET for the last six months of 1986 only, and the Company has provided no additional evidence which might support that estimate.

The Department therefore finds that any known and measurable Hydro Quebec support charges be collected through the fuel charge until an appropriate level of the expense can be determined in the Company's next rate filing. Accordingly, the Company's cost of service shall be reduced by $6,860,000.

4. Annualization of Power Sales and Purchases Expense and Transfer to Base Rates

In Western Massachusetts Electric Company, D.P.U. 1300 (1983), the Department adopted a standard which required that capacity-related charges and revenues be included in determination of the appropriate level of revenue which must be collected through base rates. We have found, *supra*, that the Pt. Lepreau performance charge should be collected through base rates under this standard and the charges relating to the MBTA contract should at this time be collected through the fuel clause. The Company has provided updates to its estimate of purchased power expense and transmission expense based on its most recent bills as a late-filed exhibit (Exh. RR-4, BE-101, pp. 25-26, revised). We find it appropriate to annualize the most recent bills provided by the Company to reflect the most recent known changes in the Company's expenses, consistent with our decision in D.P.U. 1720, pp. 65-66.

Accordingly, we find that the annualized purchased power expense which should be collected through the Company's base rates is $70,797,000, an increase of $10,232,000 to the Company's test year expense. Thus, the Company's originally proposed annualized purchased power expense of $64,210,000 must be increased by $6,587,000. In addition, we find that the annualized transmission expense which should be collected through the Company's base rates which excludes Hydro Quebec, is $3,089,000, an increase of $146,000 to the Company's test year expense. Thus, the Company's originally proposed annualized transmission expense of $9,678,000 is reduced by $6,589,000. Based on these adjustments, the transfer to base rates is $8,254,000.

B. Booking Errors

The Attorney General identified three separate errors relating to the booking of certain O&M expenses (Exh. AG-JPM-2S, p. 12). The Attorney General estimates that the aggregate effect of these three errors is to decrease the Company's cost of service expenses by $1,161,000 and to increase the Company's rate base by $914,000.

An expenditure of $184,000 was expensed during the test year but was capitalized and added to Account 506 as a post-test year addition to rate base. The Attorney General asserts that this amount should be removed from the test year cost of service. A $247,000 expense was booked twice during the test year and corrected after the test year. The Attorney General contends that this expense should also be removed from the Company's test

year cost of service. Finally, $730,000 was expensed during the test year, but subsequently capitalized. The Attorney General states that the $730,000 should be removed from test year cost of service and added to rate base. The Company agreed to the proposed adjustments (Exh. BE-124, pp. 20-21). The Department finds that the errors must be corrected; accordingly, we will reduce cost of service by $1,161,000 to remove expenses booked in error during the test year, increase rate base by $914,000 to reflect the amounts which should have been booked to plant in service during the test year but inadvertently were not, and make a corresponding adjustment of $28,801 to increase depreciation expense.

C. Coal Conversion Costs

The Company has proposed a five-year amortization of the costs incurred in preparing coal conversion plans for the New Boston and Mystic generating units. Under the Company's proposal, the total costs of $14,464,000 would be amortized over five years for an annual amortization amount of $2,893,000 (Exh. BE-100, pp. 48-50; Exh. BE-101, p. 8, L. 20).

The Company claims that, in an attempt to reduce its dependence on oil-fired generation, it prepared coal conversion plans to convert its Mystic and New Boston generating units from oil to coal. At an early stage, the Company determined that coal was not an economically viable alternative fuel for Mystic and suspended plans to convert the plant. However, BECo pursued preconstruction plans for converting the New Boston site. Engineering, financing and licensing plans were prepared and

submitted to the Department for review in D.P.U. 85-58 as part of a proposal to finance the coal conversion through an oil conservation adjustment ("OCA") charge pursuant to G.L. c. 164, sec. 94G 1/2. In July 1985, the Department denied the Company's request for an OCA charge in D.P.U. 85-58, finding that there was not a substantial probability of savings associated with converting the New Boston station from oil-fired generation to coal. The Company subsequently suspended its plans to convert the New Boston facility (Exh. AG-54).

All costs associated with the conversion projects were deferred and recorded in Account 183 - Preliminary Survey and Investigation Charges. The Company asserts that the its practice of deferring costs associated with construction projects until the project was completed or abandoned is consistent with accounting practices prescribed by the Department and the FERC (Company Brief, p. 177).

The Attorney General opposes the amortization of $2.5 million in expenses incurred by the Company from May 1981 through October 27, 1983. He contends that the recovery of pre-test year expenses would constitute retroactive ratemaking and that the expenses are unsupported by the record (Attorney General Brief, p. 71).

The Attorney General specifically objects to the $800,000 in expenses associated with waterfront work at Mystic and $280,000 in expenses paid to Stone & Webster, Inc., for health studies. The Attorney General asserts that the Company did not produce a

health study for both the Mystic and New Boston sites, but only for New Boston, and is therefore attempting to expense costs for a nonexistent study. He challenges the waterfront expenses, since that work was undertaken before the Company's decision to study conversion at Mystic, and characterizes the Company's decision to hire the Army Corps of Engineers to perform the waterfront work as an attempt to avoid environmental review (Attorney General Brief, p. 72).

The Company asserts that the study produced was undertaken for both the Mystic and New Boston sites and that no separate study for Mystic was undertaken or expensed (Company Brief, pp. 180-183). In response to the concerns regarding the waterfront work, the Company asserts that the work was undertaken while the Army Corps was dredging other portions of the area in order to achieve economies relating to environmental licensing as well as to reduce the cost of performing the work (id.).

The Attorney General also argues that expenses relating to the Mystic site should have been expensed once plans to convert that station were suspended. The Company defends its continued deferral of costs related to Mystic since the abandonment of the Mystic site as an alternative to the New Boston site was uncertain (Company Brief, p. 179). BECo argues that it discontinued efforts at the Mystic site pending the outcome of the New Boston alternative and abandoned both plans only after the issuance of the Order in D.P.U. 85-58 (Company Brief, pp. 176-180).

The Company's practice of deferring preliminary project planning expenses until a project is completed or abandoned is appropriate. Despite the Attorney General's arguments, the record indicates that the bulk of the costs relate to New Boston, with some sharing of costs between both projects. It was appropriate that all conversion planning costs be deferred until the Company decided whether to proceed with or to abandon its coal conversion project. The Company's deferral of these expenses pending a decision regarding the feasibility of the conversion project was in conformance with the Department's directives. Boston Edison Company, D.P.U. 1350, pp. 133-134 (1983). Accordingly, we find that the Company's proposed five-year amortization of the total $14,464,000 of deferred costs for the abandoned coal conversion project is appropriate.

D. Gas Conversion Expenses

In its initial filing, the Company proposed to amortize, over a three-year period, $11,637,000 in capital costs incurred in converting the New Boston station to gas-burning capability. BECo claims that a three-year amortization period matches fuel cost savings realized from the burning of gas rather than oil with the costs of converting the facility to dual-fuel-burning capability. The Company's current gas supply contract expires in 1987 (Exh. BE-100, pp. 68-69; Exh. BE-101, p. 29, l. 12.)

The Attorney General opposes the Company's proposal, arguing that gas may be available after 1987 and additional fuel savings may be realized. He claims that the capital costs of the

project should be capitalized, included in rate base and depreciated over the remaining service life of the plant (Attorney General Brief, pp. 14-17).

On brief, the Company agrees that extending the depreciation period over the service life of the plant may be appropriate. Stating that "oil and gas markets have changed in unforeseen ways" and that a supply may be available for a longer time period than originally projected, the Company concedes that "the changed situation makes the alternative life of the unit timing for this cost recovery almost equally as good" (Company Brief, p. 111). The Company thus agrees that a reduction of its depreciation and amortization expense by $3,287,000 to reflect the depreciation of the expenditure over the service life of the improvements is appropriate (id.).

The Department agrees that the accelerated amortization proposal requested by the Company is not appropriate. The capital improvements that provide the unit with dual-fired capability give the Company the flexibility to use gas if it is a lower-cost alternative or, if there is a shortage of oil, to improve the reliability of fuel supply at this unit. Thus, there is no reason to believe that this investment should not continue to provide benefits to the Company and the ratepayers for the service life of the investment. Accordingly, we adopt the Company's alternative life-of-the-unit treatment and reduce the amortization and depreciation expense by $3,287,000.

E. Inflation Adjustment

The Department grants companies an inflation allowance to recognize the effect of inflation on certain O&M expenses that are heterogeneous in nature and that are not large enough individually to warrant separate adjustment in the cost of service. See Massachusetts Electric Company, D.P.U. 200 (1980); Commonwealth Electric Company, D.P.U. 956 (1982). The inflation allowance method adopted by the Department uses a five-year average of the relationship between the level of inflation and the growth in a company's expenses.

The Company's filing included an inflation allowance of $6,507,000 (Exh. BE-100, p. 54; Exh. BE-101, p. 8, l. 33). The allowance applied an inflation factor of 6.63 percent for the 24 months ending January 1, 1987, to a residual O&M expense level of $98,149,000 (Exh. BE-101, p. 28; Exh. BE-108). In accordance with the Department's practice, the calculations have been updated based on the most recent Data Resources Incorporated ("DRI") forecast on June 2, 1986, to recognize a decrease in the inflation factor to 5.5 percent and a decrease in the Company's residual O&M expense base to $97,129,000 to reflect adjustments being made in this case to the expense items included.

The Attorney General requests that the Department reconsider its position on granting an inflation allowance. He argues that inflationary pressures have clearly eased since the institution of the inflation allowance by the Department. He also asserts that price increases alone do not explain the over 50 percent

increase in residual O&M expenses since 1980. Mr. Marquart testified that some other cause, such as an increasing mix of new expense deferrals and accrued expenses, may have caused the growth in these expenses (Exh. AG-JPM-1, pp. 21-23). He criticized the Company for failing to identify increases in specific accounts and to demonstrate any cost control efforts. Mr. Marquart suggested that, if the Department seeks to retain an automatic adjustment to recognize the effect of price increases on the cost of service, the Company should propose specific adjustments to particular accounts for those increases, recognizing in any adjustment the extent to which a price increase is offset by productivity gains, reimbursements or incremental revenues. He explained that

> For example, if these expenses represent new cost items which will produce current and subsequent revenue growth, it certainly is not appropriate to include such costs in a residual expense inflation adjustment (which may not be at all applicable to the cost item) while ignoring the subsequent cost reimbursement or incremental revenue benefits which may be realized from the cost incurrence (id., p. 23).

The Attorney General requests that his proposed revenue annualization adjustment be considered in conjunction with his arguments on the inflation allowance.

The Attorney General identifies five accounts included in the residual O&M base which he argues require more detailed and particular analysis because of the size and nature of the accounts. He contends that these accounts expense itemized materials and supplies which are replaced through inventory and

already reflect inflation, since price increases are reflected in replacement cost values included in the inventory account.

The Attorney General also attacks the inflation allowance on a theoretical basis. He argues that the inflation adjustment "is not an estimating or normalizing technique used to establish a reasonable level or rates, simply a forecast of what...might or might not happen in the future. It is giving the Company revenues for expenses that have not occurred and for expenses that may not occur" (Attorney General Brief, p. 57). He concludes that the allowance deviates from the Department's known and measurable standard for post-test year adjustments.

Critical of the use of the Gross National Product Implicit Price Deflator ("GNPIPD"), the Attorney General states that "it is common knowledge that different types of services and products will have different inflationary pressures" (id., p. 58). He argues that the GNPIPD will not correctly adjust for inflationary pressures on residual O&M even if it may accurately be used to adjust the entire gross national product for inflation (id.).

Finally, the Attorney General argues that a primary reason for an increase in expenses can be the growth in the Company's sales of electricity. He advocates that the growth in kilowatthour ("KWH") sales should be incorporated into any inflation adjustment to reflect that element's role in the historical growth of residual O&M. He suggests that such a calculation could be performed by calculating historical

residual O&M on a cents per KWH basis, similar to the cents per thousand cubic feet basis used in calculating inflation adjustments for gas utilities (Attorney General Brief, p. 59).

The City supports the Attorney General's position that the adjustment is not known and measurable.

The Company argues that the decrease in inflationary pressures is automatically reflected in the inflation factor applied to the residual O&M base. BECo supports the automatic nature of the adjustment, stating that the adjustment saves time for all parties in a rate proceeding by precluding the multitude of small adjustments that would otherwise be necessary. The Company contends that, although the accounts identified by the Attorney General are large, individual expense items are generally small, with thousands of entries, which are not susceptible to the detailed analysis advocated by the Attorney General (Company Brief, p. 154).

The Company cites the Department's past Orders to refute the Attorney General's denigration of the GNPIPD's value as an inflation index. Attacking the proposed addition of a sales adjustment to the inflation calculation, the Company asserts that only fuel costs vary directly with sales. BECo also states that even an adjustment for the slight growth in territorial sales would not reduce the ratio between the five-year average annual growth in residual O&M and inflation (Company Brief, pp. 156-157).

The Department's decision to provide companies with an inflation adjustment was a measure designed to address concerns regarding inflation and regulatory lag associated with setting rates based on a historical test year. The number of accounts included in the residual O&M base has gradually been decreased by the removal of accounts which have been separately adjusted in rate cases or which have been identified as being unaffected by inflation. Approximately 26 different items have been removed from the inflation adjustment in BECo's filing.

The Attorney General is essentially asking for a reconsideration of the Department's original policy decision. He did not offer any detailed analysis of different accounts in the residual O&M base or demonstrate that particular accounts are inflation-proof. His argument regarding the relationship between inventory and certain residual O&M expense items does not support his conclusion. While price increases may be reflected in the value of the Company's materials and supplies inventories, it is only the price increases that occurred during the test year which are incorporated in rates. Since these inventories and associated expenses will continue to be affected by future inflationary pressures, it is appropriate that they be included in the residual O&M base.

One original rationale for selecting the GNPIPD and the inflation allowance calculations was simplicity. We have often rejected more complex methods which may more accurately track expense increases but do not produce significantly different results. Eastern Edison Company, D.P.U. 837/968 (1982).

The Attorney General is correct in stating that the inflation allowance was instituted during a time of high inflation to offset increases in expenses that would not be recovered by revenue levels established based on a historical test year cost of service, but he is incorrect in assuming that the adjustment should be linked to projected changes in the level of sales. The Department's policy of basing rates on a test year cost of service is premised on the assumption that historical data for both expenses and sales provide an appropriate matching of costs and revenues. For this reason, the Department generally declines to make adjustments to test year expense levels unless such a change meets the known and measurable standard.

The inflation allowance gives recognition to the fact that known inflationary pressures tend to affect a company's expenses in a manner which can be reasonably measured. As we have found in the past, it is an adjustment which reflects the likely cost of providing the same level of service as was provided in the test year. The amount of the adjustment is based on actual inflation rates known to have occurred since the test year and on the most recent reasonable estimates of inflation projected for the six months after the date of the rate Order.

In contrast, the Attorney General requests that the Department adjust test year revenues for projected changes in demand levels and sales volumes. Such an adjustment would entail a significantly more complex analysis, incorporating many more assumptions, than the inflation adjustment. Because of the

greater level of uncertainty surrounding projections of demand which would need to incorporate demand elasticity estimates, we find that the Department's precedent of not adjusting historical test year revenues for projected changes in demand is appropriate.[8/]

Accordingly, we will permit the Company to include an inflation allowance in its cost of service. In addition, we will adjust the Company's filed residual O&M expenses to remove expenses that have been separately adjusted by the Department in this case, and will adjust expenses to reflect the levels determined to be appropriate in our findings elsewhere in this Order. The calculation of the allowance is set forth in Table 1 attached to this Order.

F. Tewksbury-Woburn Transmission Lines

BECo has included an adjustment to its test year cost of service to reflect $989,000 in expenses associated with the use of two transmission lines, M-139 and N-140, owned by New England Power Company ("NEP"). The Company asserts that these lines, which are being reconductored by NEP and run from Tewksbury to Woburn, are needed to improve the reliability of transmission to its service territory from the north. At the time of its original filing the Company stated that it expected both lines

8/ The Department has consistently rejected estimates of elasticity of demand as inherently speculative in nature and not subject to reasonable estimation, a position upheld by the Supreme Judicial Court. New England Telephone and Telegraph Company v. Department of Public Utilities, 371 Mass. 67, 71 (1976).

TABLE 1

INFLATION FACTORS

ITEM	1980	1981	1982	$1.983	1984	TEST YEAR . 7/84-6/85
RESID. O&M	$46.114	$64.869	$66.909	$83.316	$90.549	$93.118
GNPIPD	85.7	93.9	100.0	103.8	108.1	110.0

1. Compound annual percentage change in residual O&M and GNPIPD for five periods.

	Residual O&M	GNPIPD
1980-Test Year	16.90	5.70
1981-Test Year	10.88	4.63
1982-Test Year	14.14	3.89
1983-Test Year	7.70	3.94
1984-Test Year	5.75	3.54

2. Ratio of compound annual percent change in residual O&M to GNPIPD for five periods.

	Ratio
1980-Test Year	2.96
1981-Test Year	2.35
1982-Test Year	3.64
1983-Test Year	1.95
1984-Test Year	1.62
Average	2.51

3. The average ratio of the compound annual percentage change in residual O&M to the GNPIPD is 2.51: Therefore, BECO shall receive 100 percent of the projected increase in the GNPIPD.

4. GNPIPD index value at the midpoint of the test year:
   Index value 1984/4 109.60(DRI)
   Index value 1985/1 110.40(DRI)
   Index value 1/01/85 110.00 (Interpolated: compounded monthly)

5. GNPIPD index value at the midpoint of the year following the date of the Order:
   Index value 1986/4 115.60 (DRI)
   Index value 1987/1 116.60 (DRI)
   Index value 6/01/85 116.10 (Interpolated: compounded monthly)

6. Increase from the midpoint of the test year to the midpoint of the year following the date of the Order 5.55

7. Increase to be applied to the Company's residual O&M expense base: 5.55

8. Test year level of residual O&M expenses: $91.353

9. Inflation allowance: $5.070

TABLE 2

TEST YEAR RESIDUAL O&M EXPENSE BASE

	AMOUNT ($000) TOTAL ELECTRIC	TOTAL RETAIL	ALLOCATOR
O&M EXPENSE	$827.973		
LESS: Labor Expense	($118.654)		
LESS: Fuel and Purchased Power Expense	($557.002)		
SUBTOTAL	$152.317		
LESS: O&M EXPENSE ADJUSTMENTS			
Allocation of Non-Labor A&G to Steam Heating	($1.391)		
Donations	$1.880		
1984 Storm Costs	($846)		
Resdl Conservation Service	($1.053)		
Bad Debt Expense	($9.762)		
Pilgrim Refueling	($8.043)		
Nuclear Insurance	($1.191)		
Property Insurance	($5.461)		
Other Inj. and Damage Insurance	($2.033)		
Civil Penalties	($1)		
Committee on Energy Awareness	($229)		
EEI Dues	($223)		
EEI Media Expense	($150)		
Insurance Proceeds	($200)		
Joyce Capeless	($35)		
Mystic Scrubber Amortization	($471)		
Property Tax Case Legal Fees	($654)		
Rate S Litigation Costs	($71)		
LESS: Items not Subject to Inflation Allowance			
EPRI	($2.278)		
Fixed Lease Expense	($780)		
Whole Life Insurance Expensed	($1.323)		
Pensions Expensed	($5.610)		
Postage	($1.533)		
Transmission Expenses	($3.817)		
LESS: Non-Labor Portion for Contract Sales	($8.894)		
Sub-total	($54.169)		
Expenses subject to inflation per Company	$98.148	$96.100	12.3A.880/.0663
LESS: DPU Adjustments			
Transformer Rental	($1.221)	($1.185)	4.1A.105
EPRI Life Extension	($184)	($179)	11.1A.75
Booking Errors	($251)	($249)	C.B., A-8
Settlement Write-offs	($393)	($393)	
Impact 2000 House Writeoffs	($392)	($392)	
Rate Case Expense	($176)	($176)	
Donations	($1.880)	($1.838)	4.1A.123
Impact 2000 Advertising	($334)	($334)	
DPU Sub-total	($4.831)	($4.747)	
Expenses subject to inflation	$93.317	$91.353	

to be in service by July 1, 1986 (Exh. BE-100, p. 54). The $989,000 expense level includes rent for the two lines at $478,000 each per year, plus a three-year amortization of a $50,000 salvage cost to be paid for each line (Exh. BE-100, pp. 53-54; Exh. BE-101, p. 8, l. 32).

In rebuttal testimony, the Company provided a reestimate of the transmission line expenses, reducing the proposed adjustment to $902,000. The reestimate reflects the new projected in-service date of September 1, 1986, for the N-140 line. The reestimate reduces the rent for the N-140 line to reflect the two-month delay in service, and lowers the estimated salvage cost to $42,500 for each line (Exh. BE-120, p. 9).

Payments for the lines will be incurred after the lines are placed in service (Exh. BE-100, pp. 53-54). The M-139 line was energized on March 2, 1986, but the line cannot be used until the Rhode Island/Eastern Massachusetts/Vermont Energy Control ("REMVEC") permits NEP to complete certain bus work (Exh. AG-44). The Company asserts that payments are certain to be due under the contract, but did not provide any bills from NEP or indicate that any payments have been made to NEP.

The Attorney General and the City argue that the adjustment is not known or measurable for either line and should be disallowed. The Attorney General asserts that, although the M-139 line has been energized, the costs for the line are not yet known since no payments have been made.

The Company's position is that payments are due since the M-139 line has been energized, and that the expense is similar to a known and measurable wage increase. The Company states that costs associated with the N-140 line also are reasonably known and measurable since the costs are identical to the M-139 expenses, there is only a short time period before the in-service date, and the costs have been reduced for the expected two-month delay of the in-service date.

Adjustments to test year levels of expense are permitted only if the change in test year expense is known and measurable. The Department finds that costs associated with the N-140 line are neither known (since the line is not yet in service) nor measurable (since no bill or calculation that clearly establishes the level of charges has been provided on this record). Although the M-139 line has been energized, it is not clearly in service at this time since that line cannot be used until additional bus work is performed (Exh. AG-44; Company Brief, p. 138). Moreover, the projected monthly rental charge of $39,800 is a forecasted amount which has not been demonstrated to be known and measurable at this time.

Accordingly, we find that the Company's adjustment should be disallowed and cost of service reduced by $989,000.[9/]

G. New Boston Outage Expenses

During the test year, the Company incurred expenses during a

9/ We note that the Company included the support charges in its calculation of total cash working capital (Exh. AG-85). Cash working capital will be also be adjusted to remove those expenses.

forced outage at its New Boston generating unit. The Attorney General has questioned the Company's accounting treatment of certain of these expense items. He argues: (1) that the Company should have capitalized rather than expensed $770,000 in costs incurred to repair waterwalls at New Boston; and (2) that costs associated with the rental of a replacement transformer should be characterized as an extraordinary nonrecurring expense and disallowed.

1. <u>New Boston Waterwall</u>

During the test year, BECo replaced four center waterwall panels at New Boston 1. $770,000 in costs associated with the repairs were expensed and included in test year cost of service. The Attorney General argues that these costs should be capitalized because the waterwalls are clearly plant items with a service life of at least ten years (Attorney General Brief, p. 53). The Company asserts that the costs were properly expensed because the panels did not constitute a unit of property (Company Brief, p. 141). In support, the Company points to the testimony of Mr. Alpert (Tr. 16, pp. 1878-1880), who stated that costs are expensed if a unit of property is repaired or if a unit of property is only partially replaced.

The dispute centers on whether the center panels should be considered a unit of property. The Company describes the waterwalls as consisting of three sections which each constitute a unit of property and each panel as a subsection of those three sections, thus constituting only a component of a unit of

property (Tr. 20, pp. 2587-2588). We agree with the Company that expensing costs for repairs or replacements of less than the entire unit of waterwall property is, in this instance, a reasonable practice consistent with the accounting procedures set forth in the Uniform System of Accounts. Accordingly, we find the adjustment proposed by the Attorney General to be inappropriate.

2. Transformer Rental Expense

On June 16, 1984, the main step-up transformer at the New Boston power plant failed, forcing the unit to shut down. While the transformer was being repaired, it was temporarily replaced by a transformer rented from New England Electric System. Boston Edison Company, D.P.U. 84-1D-1, pp. 11-15 (1984). The cost of the repairs and the rental cost of the transformer were expensed during the test year. An insurance settlement relating to the transformer failure was received and credited to cost of service (Exh. BE-100, p. 51; Exh. BE-101, p. 8, l. 24).

The Attorney General seeks to have the rental cost of the transformer removed from the cost of service. The Attorney General characterizes the event as nonrecurring and the rental expense as nonextraordinary. He requests that $1,671,000, reflecting an increase in the Company's cost of service account, be removed from the cost of service (Attorney General Brief, pp. 53-54).

The Company challenges the Attorney General's description of the expense as nonrecurring. BECo argues that the rental cost

is an example of an expense relating to major equipment failure which the Company must incur in its regular course of business. Agreeing that the individual event and related expense item may be nonrecurring, the Company asserts that the expense category is recurring. The Company admits, however, that the expense, considered in light of the levels incurred for transformer maintenance alone, is extraordinary. The Company states that, should the expense be categorized as a transformer maintenance expense and as extraordinary for that group of expenses, the rental expense should be amortized over three years (Company Brief, pp. 143-145).

The Department finds that the rental costs constitute a nonrecurring expense that is not representative of future levels of costs. The Company agrees that the rental was a nonrecurring expense, and we find that the Company has failed to demonstrate that the expense is indicative of a recurring level of expenses related to major equipment failures.

The Department does not allow companies to include nonrecurring items in the cost of service. Nonrecurring expenses are ordinarily excluded because the expense renders the test year expense level unrepresentative of the future level of expenses which can be reasonably anticipated for the Company.

> Non-recurring expenses incurred in the test year are ineligible for inclusion in the cost of service unless it is demonstrated that they are so extraordinary in nature and amount as to warrant their collection by amortizing them over an appropriate time period. Fitchburg Gas and Electric Light Company, D.P.U. 1270/1414, p. 33 (1983).

The Department allows companies to recover over a reasonable period of time extraordinary nonrecurring expenses resulting from large, unanticipated expenditures, thus providing a reasonable and appropriate sharing of the risk of those expenditures between ratepayers and stockholders. D.P.U. 1720, p. 89.

We find that the magnitude of the $1,221,741 expense item relating to temporary transformer replacement costs is not extraordinary for this Company, and accordingly, we will reduce the Company's cost of service by that amount.

H. Nuclear Intangible Account

The Company has included $1,908,000 in its annual amortization expense associated with the depreciation of $19,078,000 of nuclear intangible plant items (Exh. BE-101, p. 29, l. 26; p. 34, l. 6). The annual depreciation expense level is based on an estimated ten-year depreciable life. The items consist of various safety-related studies mandated by the NRC, necessary to maintain the operating license at Pilgrim 1 (Exh. AG-30).

The Attorney General maintains that these items should be depreciated over a 22-year period, corresponding to the remaining service life at Pilgrim. He argues that, since the studies are necessary for the continued operation of the plant, they should be depreciated over the remaining life of the plant (Attorney General Brief, pp. 30-32).

The Company maintains that the cost of the studies should not be depreciated over the full remaining life of the plant

since the studies do not improve the unit's performance or prolong its life. The Company argues that additional studies may be required in the future and cost recovery should not be continuously delayed, which would have the effect of deferring recovery toward the end of the plant's useful life. BECo asserts that ten years is a logical period based on the plant-related nonhardware nature of the costs (Company Brief, p. 109).

We note that, although the studies did not relate to improving the unit's performance or prolonging its life, Mr. Alpert testified that the studies were required to maintain the unit's operating license (Tr. 4, p. 487). Since the studies are related to the Company's ability to maintain its operation of the plant and have, in effect, been capitalized as a portion of that plant, it is appropriate to tie the depreciation period to the remaining life of the plant: 22 years. Therefore, we will reduce the Company's depreciation expense for the nuclear intangible account to $867,000 and will decrease cost of service by $1,040,000.

I. Rate Case Expense

The Company estimated rate case expense at $176,000 in its initial filing (Exh. BE-100, p. 53; Exh. BE-101, p. 8, l. 29). The Company claims that the consolidation of D.P.U. 85-266 and an underestimation of public notice expenses resulted in an increase in its estimate of rate case expense of $25,500, to $201,500 (Exh. BE-115, p. 2). The amount has been included as

an annual expense in the Company's filed cost of service, consistent with the finding in D.P.U. 1720 that the expense recurs periodically on an annual basis. D.P.U. 1720, p. 37. The Company attributes the majority of the increase in cost to the recent change in the Department's publication requirements.

The Attorney General has proposed a two-year amortization of the rate case expenses, based on what he submits was a two-year lapse between the Company's filing date in D.P.U. 1720 and the date of the Company's filing in this proceeding (Attorney General Brief, pp. 63-64).

The Company characterizes the Attorney General's proposal as a deviation from established Department precedent of normalizing rate case expenses based on the average interval between the last four rate cases, rounded to the nearest year, and therefore argues that the expense should be recovered over one year.

A company's rate case expense is a periodically recurring expense. <u>Fitchburg Gas and Electric Light Company</u>, D.P.U. 1270/1414, p. 37 (1983). Therefore, it is necessary to normalize this expense so that only a representative annual amount of the costs of a rate case is included in the cost of service. To determine the appropriate normalization period, the Department averages the length of the intervals between the filing dates of the Company's last four rate case filings, rounded to the nearest whole year. <u>Berkshire Gas Company</u>, D.P.U. 1490, pp. 33-34 (1983). The Company's last four filings were made on October 16, 1981, November 16, 1982, December 16, 1983, and December 17, 1985. The average interval for those

filings is 1.39 years, which, rounded to the nearest year, is one year. We find that the normalization period used by the Company in its filing is correct and, based on its updated information, we will include $201,500 in its cost of service.

J. Miscellaneous Expenses

The Attorney General requested that the Company compare test year book expenses for certain accounts with the levels in those accounts for other selected time periods and explain the differences in the level of test year and prior-period account levels (Exhs. AG-71; AG-83). In the course of that comparison, the Company frequently could not attribute certain differences in amounts to any single cause. Mr. Alpert explained that the difference in amounts could be explained for certain large items, but often a multitude of small items and booking mistakes could account for other differences (Tr. 20, pp. 2619-2621).

The Attorney General has requested that $862,000 relating to "unexplained" expenses be disallowed. The $862,000 level includes $370,000 booked to Accounts 517 through 532 and $472,000 booked to Account 584 (Attorney General Brief, p. 60).

The Company argues that these expenses were grouped within each account when no major items could be found to explain differences in account fluctuation comparisons. BECo asserts that the comparisons performed are typical fluctuation analyses which are used strictly to explain the major changes in actual expenses recorded on the books in two different time periods (Company Brief, p. 163). Attacking the basis for the two

adjustments proposed by the Attorney General, the Company states that the analyses performed by BECo in response to the Attorney General's request identified the major items responsible for variations in account levels between periods and grouped the remainder of the variations together. BECo defends the practice as identical to the techniques used by outside auditors and accountants in reviewing the Company's expenses and alleges that the Attorney General's comments reflect a total misunderstanding of the process (Company Brief, pp. 163-165).

We agree that the Company's analyses conformed to normal accounting practices and that the Company's accounting adjustments do not represent a significant level of unexplained expenditures. Accordingly, we reject the Attorney General's proposed adjustment.

K. Pilgrim 1 Decommissioning Fund

1. Decommissioning Expense

The Company has included in its prefiled cost of service an adjustment of $5,026,000 for an annual recovery of projected decommissioning expenses. This expense is based on the updated estimate of $121,694,000 for total decommissioning expenses when Pilgrim 1 is retired, as presented by the Company's witness William J. Manion (Exh. BE-101, p. 29; Exh. BE-400). The decommissioning of a nuclear generating unit includes dismantling the unit and removing radioactive materials from the plant site. The Department requires companies to collect funds dedicated to decommissioning activities in advance so that current ratepayers who receive the benefits of the generation of

the plant pay the costs associated with providing that generation. Boston Edison Company, D.P.U. 1350, p. 94 (1983); Western Massachusetts Electric Company, D.P.U. 957, p. 78 (1982).

In D.P.U. 1720, based on the decommissioning estimate of $93,437,000 presented by Mr. Manion, the Department allowed an annual recovery of $3,748,000 for decommissioning costs. No party opposed the decommissioning study or the requested level of expense.

The Department finds that the Company's cost of service adjustment for the costs of decommissioning its Pilgrim 1 nuclear plant is appropriate.

2. Management of the Fund

In D.P.U. 1350, the Department ordered the Company to hold amounts collected from retail customers for decommissioning in separate interest-bearing accounts to guarantee that funds collected for decommissioning are available when the unit is retired and to minimize the possibility that future ratepayers will bear the burden of additional retirement costs. The Company was directed to structure a decommmissioning fund that would maximize the after-tax return on these ratepayer-supplied funds and minimize the overall cost of decommissioning to its customers. D.P.U. 1350, pp. 94-96.

Certain changes in the tax laws have occurred since D.P.U. 1350 which provide a partial deduction for utilities contributing decommissioning funds to a tax-exempt trust and exempt from taxation the interest earned on the companies'

deductible contributions to the trust. The new tax law, codified as Section 468A of the Internal Revenue Code ("Section 468A"), became effective on July 18, 1984, but the Treasury has not yet issued regulations implementing the law (Tr. 25, pp. 3341-3342). The Company has not formulated a long-term investment plan for its decommissioning funds and has invested the funds in short-term U.S. government securities since the summer of 1983 (Exh. HO-102).

BECo's decommissioning fund consists of a series of separate, interest-bearing accounts. Pilgrim unit contract customers pay amounts into the fund directly to the bank as a separate contract payment, and tax liabilities are paid out of the account balances. BECo has a separate account for its retail customers. BECo makes deposits net of taxes to the fund for its territorial customers and pays taxes for the fund separately (Tr. 25, p. 3357).

In September 1985, the Company set up a trust fund retroactive to July 18, 1984, under the provisions of Section 468A (Exh. BOS-9). Funds collected after July 18, 1984, are eligible for a limited deduction of two-thirds of the annual decommissioning expense (Tr. 25, pp. 3334-3336). One-third of the annual expense is deposited in a fund other than the trust fund which also contains amounts collected before July 18, 1984, with the other two-thirds of the decommissioning allowance being deposited in the trust fund. The Company can deduct its contributions to the trust, for federal tax purposes, and the interest on the trust's earnings is exempt from federal taxes.

The alternatives for investment of the trust deposits are limited by Section 468A.

Nontrust fund amounts invested in Treasury bills and Treasury notes are exempt from Massachusetts corporate franchise tax, but are taxable at the federal level. The Company has not yet selected a long-term investment policy for these funds. The pretax rate of return on these funds was 7.4 percent in calendar 1985 (Exh. BOS-10).

The City requests that the annual decommissioning expense sought by the Company be reduced by offsetting the annual expense amount by the amount of interest earned by the funds. In estimating its proposed interest credit amount, the City projected a net pretax rate of return for the funds of 3.785 percent, incorporating an average annual yield of 7.19 percent and an annual inflation factor of 3.365 percent. Recommending that the Company's proposed annual decommissioning expense be adjusted to reflect this "real" return, the City reduced the proposed expense level by $188,000 to $4.85 million per year. The City requests that the Department order the Company to incorporate fund earnings estimates in its updates to decommissioning expense estimates in all future rate filings (City Brief, pp. 33-35).

The Company opposes the City's proposed interest adjustment. BECo states that the Company incorporates expected earnings on funds in its decommissioning estimate by assuming that the compounded after-tax earnings from the funds will offset the effect of inflation. The Company also attacks the

City's derived real rate of return, arguing that the after-tax return on funds is a negative 0.8 percent (Company Brief, p. 161).

We find that any separate adjustment to recognize fund earnings is inappropriate at this time. The Company was ordered to establish separate accounts to ensure that sufficient funds would be available to meet decommissioning expenses when the unit was retired and ready for decommissioning. The Company is correct in stating that interest income on the fund was projected in its initial study and incorporated in the determination of the amount which would be available for decommissioning when the time occurred. If we allowed the City's adjustment, we would be preventing the Company from receiving the full amount of projected decommissioning costs, thus defeating our original purpose and ignoring the estimate that we accepted in D.P.U. 1720.

The City also challenges the Company's efforts to maximize the after-tax return of the decommissioning funds, and is critical of the Company's interpetation of and compliance with Section 468A (City Reply Brief, pp. 22-24). More specifically, the City contends:

> ...the Company's judgments that (1) interest earned by the decommissioning trust fund and allowed to reinvest in the fund is not permitted an offsetting deduction under IRC Section 468A and (2) Section 468(A) locked in a ratio at the time the statute was passed that effectively prevents the Company from deducting fully one-third of decommissioning monies collected from ratepayers, which monies are placed in an exclusive, segregated trust fund that is not utilized by the Company for any purpose except and until the plant's decommissioning (id.).

We agree that the Company's efforts to minimize the tax effects on the decommissioning funds collected from ratepayers should be enhanced. Mr. Alpert testified that the choice of the best investment alternatives had been delayed by the passage of the new tax provisions and the lack of direction by the Treasury in issuing related regulations (Tr. 25, pp. 3373-3374). More troubling, however, were his statements that the Company's efforts to enhance fund earnings by selecting the best investment alternatives have been limited because of the size of the funds. "Until they reach a significant size, there's no purpose in great efforts to try and invest the funds, because you're not going to find that your earnings is [sic] greatly enhanced. You need a sizeable sum to really consider a significant search for investment vehicles" (Tr. 25, pp. 3373-3374). While Mr. Alpert is correct that the after-tax return on a fund of $2 million offers less economic incentive for an extensive canvassing of investment alternatives than return on a fund of $100 million, the effort to minimize the tax impact on funds collected from current ratepayers is crucial to the Company's fiduciary obligation to manage those funds in an efficient and economical fashion for the ratepayers. In permitting the Company to collect funds prospectively for the decommissioning costs, the Department has emphasized that future ratepayers, who will not receive the benefit of the Pilgrim unit's generation, should be shielded from the burden of bearing any additional costs associated with decommissioning should the fund prove inadequate. To forestall that eventuality, we have

permitted the Company frequent updates to its decommissioning estimates. Furthermore, in order to ensure that funds collected from present ratepayers are used in the most economically beneficial fashion, the Department has directed the Company to maximize the after-tax return on the fund.

We understand that the Company has undertaken certain efforts to minimize the tax effects on decommissioning funds collected from the ratepayers. For example, the creation of the trust fund pursuant to Section 468A has reduced the level of taxes which would otherwise offset the contributions collected from customers. However, to protect the value of funds currently contributed to the fund, the Company should improve its efforts to clarify the tax issues relating to both trust fund and nontrust fund amounts. In addition, the City has provided a copy of a federal decision which may offer an avenue for the Company to minimize further the tax effects on decommissioning funds collected from ratepayers (City Reply Brief, p. 24; App. A). We expect the Company to address the issue of its efforts to maximize the after-tax return on these funds in its next rate filing and to provide a report as part of its prefiled testimony which addresses the tax aspects of the Company's contributions to the fund and the trust fund; the tax aspects of the fund earnings; and the alternatives considered and selected to satisfy the Company's fiduciary obligation to maximize the after-tax earnings of the funds collected from ratepayers.

L. Pilgrim Outage Expenses

1. Background

BECo's Pilgrim 1 nuclear generating unit, like other nuclear power plants, must be removed from service periodically for routine refueling and maintenance. In past cases, the Department has determined that the incremental cost of the refueling outage was a periodically recurring expense. Accordingly, for ratemaking purposes, the Department determined a representative level of such expense by normalizing the most recent refueling outage cost over the Company's refueling outage period. D.P.U. 1720, pp. 39-41. In this case, the Company determined the incremental cost of the refueling outage to be $34,657,000 by reducing the total nuclear expenses incurred during the outage period ($75,720,000) by the level of annually recurring, nonoutage-related nuclear expenses for the period ($40,000,000) and insurance credits for the outage ($1,063,000) (Exh. BE-101, p. 23).

The Pilgrim 1 nuclear unit was shut down from December 10, 1983, through December 30, 1984 (Exh. BE-100, p. 34). The extended outage period was needed to make repairs ordered by the NRC, including major pipe replacement. The Company proposed that the net incremental expense for the outage be amortized over a five-year period (Company Brief, p. 82).

2. Positions of the Parties

The Attorney General claims that the Company's calculation of refueling outage expense is, in effect, retroactive

ratemaking because it would permit the recovery of pre-test year expenses. Based on the testimony of Mr. Marquart, the Attorney General proposes that the Company be allowed an average of $15.727 million in outage expenses, normalized over a two-year period (Exh. AG-JPM-2(S); Attorney General Brief, p. 19).

The Attorney General also requests that the Department reduce the Company's rate base by $13,136,384 because of BECo's imprudent management of Pilgrim 1, as cited by the Department in D.P.U. 86-1A-B in relation to outages during the test year. The Attorney General calculated the adjustment by multiplying that portion of the total year that Pilgrim 1 was found by the Department to have been out of service because of imprudent management (9.5 days/365 days) by the net nuclear plant on December 31, 1984 ($521,171,761) (Attorney General Reply Brief, pp. 5-6).

The Company asserts that the year-long outage at Pilgrim 1 resulted in the incurrence of extraordinary costs and that, consistent with Department precedent, such costs may be recovered through amortization (Company Reply Brief, p. 16). The Company also argues that the Attorney General's assertions regarding the exclusion of pre-test year costs for nuclear refueling outage expenses are irrelevant to the issues being decided here (id.).

On the issue of the rate base reduction for Pilgrim 1 mismanagement, the Company responds that a per se adjustment of

rate base is not supported by evidence on the record or Department precedent, and is inconsistent with the provisions of G.L. c. 164, sec. 94G, which sets the penalty for company imprudence as the disallowance of higher replacement power costs resulting from any improper management. The Company claims, therefore, that its ratepayers will be refunded the full amount of their losses associated with the Pilgrim 1 outages through the fuel charge adjustment (Company Reply Brief, pp. 11-12).

3. Analysis

In Western Massachusetts Electric Company, D.P.U. 84-25 (1984), the Department considered the ratemaking treatment for nuclear fuel outage expenses. Consistent with Department policy, periodically recurring expenses associated with the nuclear fuel outages were normalized, and abnormal expenses were amortized. In recent cases involving BECo, there has been no attempt to distinguish between a normal and an abnormal level of expenses; the incremental expense of the most recent outage was deemed to be a representative level of the recurring expense for purposes of normalization. As the Company notes, its 1983-1984 outage expenses were extraordinary in amount because of the duration of the outage. The expense is clearly unrepresentative of future outage expenses and may not be used for normalization purposes. These facts underscore why, in D.P.U. 84-25, the Department emphasized the importance of determining what portion of outage-related expenses is normal and recurring, and what portion is nonrecurring and abnormal. Without a finding as to

the normal, recurring level of outage expense, it is impossible to normalize the fuel outage expense.

Based on the record, we find that the Company has reasonably computed an incremental outage expense for the extended outage to be approximately $35.7 million. The record does not, however, clearly establish what portion of that expense is normal and periodically recurring, and what level is abnormal and nonrecurring. Our experience with BECo and Western Massachusetts Electric Company has demonstrated only that the costs associated with nuclear plant outages are volatile and unpredictable, making attempts to normalize the expense administratively burdensome and unproductive. Accordingly, we have determined that it is both necessary and appropriate to revise our policy on nuclear fuel outage expenses. We will henceforth permit companies to amortize nuclear fuel outage expenses and to reflect the amortizations in rates.

We will, therefore, adopt the Company's proposal to amortize its 1983-1984 nuclear refueling outage expenses, with one adjustment. During the time that the outage took place, the Company's rates included a normalized level of nuclear refueling outage expense of $9,329,000, approved in D.P.U. 1350 and D.P.U. 1720. Since the normalization period of two years set in D.P.U. 1720 would expire by the effective date of rates set in this Order, it is appropriate to permit the amortization of outage-related expenses only to the extent they were in excess of that level which was being collected from ratepayers through the then existing rates. Accordingly, the Company may amortize

over a five-year period $25,328,000, the difference between the net incremental outage expense for the 1983-1984 outage ($34,657,000) and the normalized level included in rates at that time ($9,329,999). The Department will, thus, decrease the Company's O&M expense to remove all booked outage costs, and provide for an amortization of that portion of $5,065,000 ($25,328,000 / 5 years) as adjusted for contract sales and the retail allocation.

The Attorney General has proposed a rate base adjustment relating to the Pilgrim 1 shutdown attributable to Company imprudence, but the Department agrees with the Company that the adjustment proposed by Attorney General would constitute a substantial departure from Department precedent and that the record in this case is not sufficiently developed to permit the Department to consider this important policy matter. As the Company indicates, the proposal was made for the first time on reply brief. Therefore, the Department declines to rule on the matter. Accordingly, the Attorney General's proposal is denied.

M. Uncollectibles

The Department has consistently permitted companies to include a representative level of uncollectible revenues as an expense in cost of service for ratemaking purposes. In Boston Edison Company, D.P.U. 1720 (1984), the Department revised its

standard for this ratemaking item, establishing the average of the most recent three years' net bad debt write-offs as a percentage of revenues as the appropriate level of uncollectible expense for inclusion in the cost of service. In determining uncollectible expense, the Department allows a company to use a three-year weighted average of net write-offs to total revenues and to apply that percentage to test year revenues.

In D.P.U. 1720, the Department also included $500,000 in the Company's cost of service for the amortization of an extraordinary uncollectible expense, specifically the three-year amortization of a $1,500,000 debt involving U.S. Department of Housing and Urban Development ("HUD") properties.

In compliance with the standard set forth in D.P.U. 1720, the Company had initially included an uncollectible expense of $10,227,000 in its cost of service (Exh. BE-101, p. 22). The Company included actual HUD write-offs for 1983, 1984 and 1985 in the three-year weighted average used to determine the level of uncollectibles (Exh. AG-81).

The Attorney General, through the testimony of Mr. Marquart, has confined his opposition to the Company's uncollectible expense calculation to three areas: (1) use of the years ending June 30, 1983, 1984 and 1985, rather than calendar years 1983, 1984 and 1985 to determine the three-year weighted average (Exh. AG-JPM-1, p. 24); (2) use of unadjusted test year revenues as opposed to adjusted test year revenues in the calculation (Exh. AG-JPM-1, p. 24); and (3) inclusion of actual HUD write-offs to determine the weighted average.

The Attorney General argues that the HUD write-offs should be removed from the uncollectible expense calculation. At the same time, the Attorney General asserts that the Company is not entitled to recover $500,000 for a third consecutive year. The Attorney General further contends that the inclusion of actual HUD write-offs in the calculation of a representative amount results in both a double recovery of the expense and an absolute dollar recovery which was not envisioned by the Department in D.P.U. 1720. The Attorney General's proposed adjustments to uncollectible expense would amount to a $987,000 reduction in the Company's cost of service as filed (Attorney General Brief, pp. 46-47).

The Attorney General also contends that the Company's uncollectible expense has increased 22 percent since D.P.U. 1720 without adequate explanation (Exh. AG-JPM-1S, p. 7). The Attorney General has requested that the Department require the Company to submit in its next rate case filing an explanation of why BECo is unable to control this situation (Attorney General Brief, pp. 49-50).

The Company has agreed to the use of the more recent calendar years and adjusted test year revenues in the weighted average calculation (Company Brief, pp. 130-131). The Company contends, however, that if actual HUD write-offs are removed from the three-year weighted average calculation, then the three-year amortization of $500,000 per year which began in July 1984 should continue through the 12 months following the

decision in this case (Exh. BE-124, p. 7; Company Brief, p. 132). Consistent with that position, the Company argues that its cost of service as filed should be reduced by only $487,000.

In response to the Attorney General's contention regarding the overall level of uncollectibles, the Company claims that the Department's billing, termination and security deposit regulations are the main reasons for the rise in bad debts (Company Brief, p. 134).

The Department agrees with the Attorney General that use of the most recent calendar years for calculating normalized bad debt was approved in D.P.U. 1720 and remains appropriate in this case. Additionally, we find that a determination of the weighted average based on adjusted test year revenues, as opposed to unadjusted figures, is consistent with the Department's goal of achieving a more accurate representation of uncollectible expense.

The Department further finds that the Company's proposal to include actual HUD write-offs in its calculation is inappropriate. In separating the HUD debt from other uncollectibles in D.P.U. 1720, the Department determined that the nature of the HUD debt was so extraordinary as to merit amortization over a period of years. A debt that was too large to include in the uncollectibles calculation in D.P.U. 1720 should not now be incorporated in a normalized calculation.

At the same time, the Company is entitled to recover an amortized portion of the HUD bad debt for a third and final

year. There is no reason to terminate the amortization period prescribed in the last rate case. Consequently, we must disallow the adjustment proposed by the Attorney General.

In sum, the Department finds that (1) actual HUD debt write-offs should be removed from the Company's calculation of the normalized uncollectible expense; and (2) the Company is entitled to include in its cost of service $500,000 as the amortized portion of its HUD debt. The result of these changes, along with the use of calendar years and adjusted test year revenue in the calculation of uncollectible expense, reduces the Company's cost of service by $487,000.

Finally, we concur with the Attorney General that the increasing level of uncollectible expense over past rate cases warrants further inquiry. We note that the billing and termination regulations promulgated by the Department have not significantly changed over the last three years and, therefore, are unlikely to explain fully the reason for increased uncollectible costs. Consequently, we order the Company to provide the Department, in its next rate filing, with a detailed explanation of its uncollectible debt experience (including a breakdown between residential and business accounts) and documentation of the steps taken to address that situation.

N. Charitable Donations

The Company has included $1,880,000 in its cost of service for donations made to charities and other institutions. Most of the Company's donations were made to the Boston Edison

Foundation ("Foundation") (Exh. AG-73), a private association comprising a number of members of BECo's board of directors. The Foundation, in turn, distributes funds provided by the Company to various educational, cultural and charitable organizations (Exhs. AG-194, AG-195; Tr. 20, p. 2504).

The Attorney General recommends that the Company's donations ultimately be borne by the shareholders but, for the purposes of this case, be shared evenly by the ratepayers and shareholders. In support of his contention, the Attorney General argues that (1) the Foundation checks with the Company before making large donations; (2) the $100,000 donation made by the Foundation to Boston College for a chair in the name of Thomas J. Galligan, a former BECo chief executive officer, is a prime example of an improper contribution; (3) ratepayers presently pay the full cost of these contributions without being afforded any input into decisions regarding contributions; and (4) the Company and the Foundation presently have no incentive to act prudently or reasonably in making contributions where they bear no cost responsibility (Attorney General Brief, p. 70).

In addition, the Attorney General notes that the amount included in the cost of service reflects donations accrued during the test year (Exh. AG-24, p. 337A; Tr. 20, pp. 2560-2561), and he argues that the cost of service should be reduced by $165,000, representing the difference between donations accrued and donations paid.

The Attorney General, through his cost of service witness, has noted that "some regulators, recognizing the corporate and societal benefits of charitable contributions, have assigned these benefits and donations to the corporate shareholders of the utility. Others have shared the goodwill among shareholders, employees and customers" (Exh. AG-JPM-1, p. 9).

In New England Telephone & Telegraph Company v. Department of Public Utilities, 360 Mass. 443, 489 (1971), the Supreme Judicial Court held that a regulated utility could properly expend reasonable amounts for charitable purposes. In addressing the New England Telephone case, the Attorney General contends that that case does not "give the Company the right to charge ratepayers for all contributions which it makes" (Attorney General Brief, p. 68). The Attorney General also cites testimony of the Company's cost of service witness stating that he could not confirm whether the Company would have made the same level of contributions if the money were not recoverable from the ratepayers (Tr. 20, p. 2517).

The Company argues that (1) BECo has made these donations to worthy recipients under appropriate procedures; (2) the New England Telephone case is the controlling precedent in this area; and (3) accrual accounting is entirely appropriate and there is no basis on which to claim that charitable donations should be treated on a cash basis.

In addition, the Company asserts that the Department is restricted from altering its rule on donations (Company Brief, p. 174), citing the Court's language:

> When a major change in the regulatory standard is in prospect, there should ordinarily be warning sufficient to enable the Company to adjust both its practices and its proof to the new situation. New England Telephone & Telegraph Company v. Department of Public Utilities, 371 Mass 67, 84 (1976).

The Department finds that the actual test year donations serve as a more representative indication of the Company's likely future charitable expenditures than donations accrued during the test year. While the Company uses the accrual method of accounting for these donations, the amounts, according to Mr. Alpert, "accrue based on estimates of how much may be contributed, and the decision to contribute is actually made later" (Tr. 20, p. 2561). The Company has failed to show that its estimates have any relationship whatsoever to donations ultimately made. The use of actual test year donations reduces BECo's test year level by $186,000.[10/]

As the Attorney General points out, the Supreme Judicial Court in New England Telephone, supra, 360 Mass. at 489, did not rule that all funds expended by a utility for charitable donations should automatically be included in a company's cost of service for ratemaking purposes. Clearly, if a company fails to demonstrate that the amount it expended was reasonable and

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10/ The Company's actual test year donations of $1,694,000 comprised $1,750,000 given to the Foundation plus $49,000 given directly to other charities, less $45,000 given to the Massachusetts Taxpayers Foundation. This total was then allocated to electric customers based on the Company's allocation factor of 96.58 percent (Exh. AG-73; Exh. BE-101, p. 15).

that its selection of beneficiaries was proper, such donations may be disallowed. Id.

While the Company was able to provide information regarding its method of selecting worthy recipients of the ratepayers' charity, it provided no information regarding how the Company determines whether the overall level of donations is reasonable.

Based on this record, the Department finds that BECo has failed to sustain its burden of proving that the amount of charitable expenditures included in its cost of service is reasonable. Given this finding, the Department could disallow all such costs in this case. We realize, however, that the evidentiary burden to prove the reasonableness of the level of such expenditures is inherently heavy. The evidentiary problem is that, unlike other expenses included in the cost of service, the amount expended for charities bears no quantifiable relationship to the Company's ability to provide utility service to its ratepayers. Recognizing (1) that it is difficult to demonstrate what a reasonable level of contributions is, and (2) that donations are, in effect, involuntarily made by ratepayers, the Department finds that it is appropriate to revise traditional Department treatment of such contributions in order to introduce an incentive for Company management to ensure that its level of contributions is reasonable.

In order to balance the equities and develop a rational, workable solution to the difficulties associated with adjudicating this issue, the Department will in this case, and in the future, permit companies to include one-half of their

charitable donations in the cost of service, as long as the charities selected are not found to be improper. This policy will, in effect, share the costs of the expenditures equally between the shareholders and ratepayers. In this manner, the Department will have some assurance that utility managers will expend reasonable amounts for legitimate charities because they will be spending both shareholders' money and ratepayer funds.

Although BECo has argued that a change in the regulatory standard regarding charitable contributions requires sufficient warning, we find that our decision in this matter affords adequate notice and does not prejudice the Company. We remind the Company that the ratemaking process is prospective in nature. Rates set here are designed not to recover past expenditures, but rather to provide a reasonable level of revenues to cover a representative amount of future costs. The Company can guide its future conduct with full knowledge of the Department's ratemaking treatment.

Accordingly, the Company's cost of service should include $847,000, or one-half of test year actual donations to allowable charities. Thus, the Company's cost of service shall be reduced by a total of $1,033,000.

O. EEI Membership Dues and Expenses

The Edison Electric Institute ("EEI") is an organization which conducts research, communication and lobbying activities on behalf of the electric utility industry. BECo is a member of EEI. In past rate cases, the Department has disallowed that

portion of EEI dues related to the organization's lobbying activities. In the Company's last rate case, the Department rejected the Company's narrow definition of "lobbying" and placed the burden on the Company to provide specific dues expense data from which one might clearly distinguish between "EEI's actual lobbying activities, as viewed by the Department, and those supporting EEI's legislative activities." Boston Edison Company, D.P.U. 1720, p. 75 (1984). In that case, the Company's failure to provide specific dues data prompted the Department to eliminate 20 percent of test year membership dues from cost of service.

In the test year, the Company made dues payments of $226,000 to EEI. The Company booked approximately $3,500 below the line and removed an additional $42,000 from cost of service, together representing 20 percent of EEI dues, allegedly in conformance with the Department's Order in Boston Edison Company, D.P.U. 1720 (1984). Of the $42,000 adjustment, $33,000 was removed from O&M expense and an additional $9,000 of capitalized EEI dues was removed from plant in service (Exh. AG-129).

In addition, BECo made several separate payments to EEI other than its dues payment. These payments included $149,000 to the Three Mile Island Cleanup Program ("TMI Cleanup Program"). According to the National Association of Regulatory Utility Commissioners ("NARUC") Report of EEI Financial Operations for the fourth quarter of 1984 (Exh. AG-128), the TMI Cleanup Program, a separately funded project which began in 1985

and is scheduled to continue through 1991, supports the radioactive decontamination of the Three Mile Island nuclear generating station No. 2 in Pennsylvania.

The Attorney General contends (1) that the Company has failed to distinguish between dues expense related to lobbying and dues expense related to other activities; and (2) that the Company has failed to demonstrate the direct benefits to ratepayers of any EEI expense. The Attorney General notes that the Company has failed to produce EEI's Budget Book, as requested by both the Attorney General and the Department (Exh. AG-127). Instead, the Company provided two NARUC reports regarding EEI operations (Exh. AG-128), covering nine months of the test year. The Attorney General also notes that only one NARUC report, addressing three months of the test year, has been audited.

The Attorney General argues that the dues expense of $226,000 has not been properly accounted for by the Company. He notes that BECo has presented only one lump-sum invoice for the test year and speculates that the Company would be unlikely to pay such a large invoice to any other vendor without further documentation (Attorney General Brief, p. 78).

In arguing that the Company has not adequately demonstrated the direct benefit to ratepayers of any activity supported by EEI dues, the Attorney General notes that Mr. Alpert, the Company's cost of service witness, was unable to quantify any such benefits in "dollars and cents" (Tr. 16, p. 1805). The

Attorney General is not persuaded by testimony of Mr. Alpert expressing the belief that the benefits of EEI membership outweigh its costs and that further examination of EEI's service would be "too expensive" and a "low value undertaking" (Tr. 16, p. 1810).

The Attorney General also contends that the $149,000 payment to the TMI Cleanup Program should be removed from cost of service, noting that the Company has failed either to justify the amount or to specify the benefits to ratepayers of such an expense.

Finally, the Attorney General argues that EEI maintains a membership in the Metropolitan Club, a Washington, D.C. club that denies membership to women. In arguing that ratepayers should not bear the cost of EEI's membership in a club that discriminates on the basis of gender, the Attorney General notes that the Company has failed to show the benefits of the club membership to either EEI or the Company (Attorney General Brief, p. 86).

The Company argues that the record clearly demonstrates that BECo's ratepayers derive benefits from the Company's participation in EEI. The Company points to assistance from other EEI members during Hurricane Gloria and EEI's Plant Operation Selection System, which assists the Company in measuring the qualifications of job applicants (Exh. AG-134), as examples of the continuing benefit of EEI membership to ratepayers.

The Company further contends that the issue of allowance of EEI dues expense was settled in D.P.U. 1720. BECo notes that extensive testimony on the operation and function of EEI was presented in that case and argues that it would be "an unworkable and burdensome procedure" to require the Company to present a "full-dress evidentiary case" on this issue in every rate filing (Company Brief, pp. 187-189).

The Company also contends that the TMI Cleanup Program has the potential for having "both near and long term benefits to the Company and its ratepayers," citing the commitment of TMI's owner to share all information with utilities which have made payments to the program (Company Brief, p. 192).

In the last two rate cases, the Department has expressed its concern regarding the Company's inability to provide documentation to distinguish between those EEI expenses which support lobbying activities and those which support other activities that directly benefit the Company's ratepayers. Boston Edison Company, D.P.U. 1720 (1984); Boston Edison Company, D.P.U. 1350 (1983). In this case, the Company has failed to provide the EEI Budget Book, a document which could immeasurably assist the Department in determining what portion of EEI dues supports activities which directly benefit the ratepayers. Instead, the Company has presented a letter from Robert Baum, EEI's general counsel, stating that the Budget Book is confidential and offering the opinion that the reports of the NARUC Oversight Committee contain the "best evidence available

to demonstrate the actual resource allocation of EEI" (Exh. AG-127). In fact, the NARUC reports submitted by the Company address only nine months of the test year and fail to provide documentation of EEI's benefit to ratepayers.

In light of the Department's concern regarding EEI dues, as expressed in both D.P.U. 1350 and D.P.U. 1720, we find that the Company has failed to show that any of its test year EEI dues should be included in cost of service. The Department's decision in D.P.U. 1720 to eliminate 20 percent of EEI dues expense from cost of service cannot be interpreted as relieving the Company of its obligation to show that some portion of test year EEI dues expense is designed to benefit ratepayers. While the Company claims that fulfilling such an obligation in every rate filing would be "unworkable and burdensome," the Department suggests that the submission of the EEI Budget Book or other supporting documentation in future rate cases may, in fact, work toward alleviating any such burden. Nor does the Company's mere assertion that EEI membership provides some unquantifiable benefit to ratepayers relieve it of the duty to show why monies used for membership dues in a club that discriminates against women should be recoverable from the Company's ratepayers.

Similarly, the Department finds that the Company has failed to demonstrate that BECo's contribution to the TMI Cleanup Program is a reasonable expense. Contrary to the Company's assertions, the record does not demonstrate that the level of payments will produce a corresponding benefit enhancing BECo's

operations or benefiting its ratepayers. The record does not establish that the project is a research program designed to gather information for the future benefit of the nuclear industry; rather, it appears on its face that the payments are primarily intended to assist the owner of Three Mile Island in its cleanup responsibilities. The Company's assertion regarding the commitment of TMI's owner to share information from the project is unpersuasive. The Company did not substantiate or quantify its claim and, consequently, BECo has failed to demonstrate that its ratepayers should in any way be required to contribute to the Three Mile Island cleanup effort.

Accordingly, we will reduce the Company's proposed cost of service by (1) $149,000 for payments made to the TMI Cleanup Program; and (2) $181,000 to remove the remaining EEI annual dues.[11/]

P. EPRI Life Extension Program

The Company has included $651,000 in its cost of service for test year expenses associated with the Electric Power Research Institute's ("EPRI") Life Extension Program (Exh. AG-112).[12/] The EPRI Life Extension Program is a cooperative research project which began in 1984 and ended in December 1985. The

11/ In accordance with the Company's allocation of EEI dues expense (Exh. AG-129), $142,000 will be removed from expenses and $39,000 from rate base.

12/ The Company has accepted Mr. Marquart's recommendation to remove $184,000 of capitalized post-test year expense from cost of service and add it to rate base (Exh. BE-124, p. 21; Exh. AG-JPM-1S, MAG Exh. (A)-8).

EPRI Program was designed to develop a comprehensive set of system guidelines for evaluating the plant life extension alternative to construction of new plants. The project, which centered on the evaluation of Mystic Unit 6, was undertaken to provide industry-wide guidelines, with possible, particular benefit to BECo. The net cost of the entire EPRI Program, including expenses outside of the test year, was $1,131,000, representing $1,625,000 total expenditures less a $494,000 reimbursement from EPRI (Exh. AG-27).

Noting that the EPRI Life Extension Program may be of some benefit to BECo's ratepayers, the Attorney General urges that these expenses are nonrecurring and should be amortized over three years, with one-third remaining in test year cost of service, so as to share the costs and possible benefits between BECo and its ratepayers. The result of this amortization would reduce the Company's cost of service by $434,000.13/

The Company argues that (1) although the EPRI Life Extension Program has been completed, life extension costs for all BECo plants will recur in the future; and (2) the EPRI Program is of particular benefit to the Company (Company Brief, pp. 146-150).

The Company's cost of service witness stated that the EPRI Life Extension Program is not a one-time expense, but "the first expenditure of a continuing series of expenditures to extend

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13/ The Attorney General has accepted testimony of Mr. Alpert stating that total test year EPRI Program costs amounted to $835,000. This reduces the Attorney General's proposed downward adjustment from $631,000 to $434,000 (Attorney General Brief, p. 55; Exh. BE-124, p. 20).

unit life" (Exh. BE-124, p. 18). Mr. Alpert further testified that future expenditures in this area can be expected to increase as future life extension activities will involve fewer tests and more maintenance items. In essence, Mr. Alpert concluded that the EPRI Life Extension Program is just one aspect of the Company's extensive life extension projects at all of its plants, activities that include intensified maintenance, testing, surveillance and additions to generating units on a continuing basis (id., p. 18). Mr. Alpert claimed that only $550,000 of the $1,600,000 total EPRI Program expenses has been dedicated to activities with industry-wide application, while the bulk of the contractors performed physical, in-plant life extension work on BECo units (Company Brief, p. 147; Exh. BE-124, p. 19).

The Department finds that the test year expenses associated with the EPRI Life Extension Program represent the first costs to the Company associated with overall life extension activities for all of its plants. The Company has demonstrated that it is presently involved in life extension activities at all of its plants, activities which are not clearly distinguishable from those associated with the EPRI Life Extension Program. Although the work performed under the EPRI Program was part of an overall study with an eye toward industry-wide benefits, the vast majority of EPRI work amounted to in-plant physical work at Mystic 6 which the Company expects to continue in the future. In fact, the Company's authorization of $4,478,000 for "Life Extension & Performance Improvement" in 1986 for all plants

(HO-RR-8) indicates that the Company has a commitment to continuing life extension activities above the test year EPRI Program expense.

In summary, the Company has presented substantial evidence that these test year costs will recur in the future, and, therefore, we reject the Attorney General's proposed three-year amortization of costs. Accordingly, we find that the full test year expense of $651,000 associated with the EPRI Life Extension Program should be included in the Company's cost of service.

Q. Storm Costs: 1984 and 1985

In D.P.U. 1720, the Department found that costs incurred as a result of a March 1984 wind and snow storm were extraordinary and allowed costs of $4,410,000 to be amortized over five years. That represented the second rate case in which the Department amortized storm costs over five years, having afforded similar treatment to costs incurred as the result of a May 1977 storm. Boston Edison Company, D.P.U. 19300 (1978).

In this case, the Company has requested an increase in cost of service of $51,000 for 1984 storm costs (Exh. BE-101, p. 8). This increase represents the difference between storm costs of $4,410,000 as set forth in D.P.U. 1720 and the Company's final storm costs of $4,454,000 (Exh. BE-100, p. 33; Exh. BE-101, p. 20).

In September 1985, Hurricane Gloria caused damage to wide areas of Massachusetts. The Company, in its initial filing, estimated the incremental expense of Hurricane Gloria to be

$10,200,000, including incremental labor costs and costs of line and tree crews (Exh. BE-104). Pursuant to the Department's decision in D.P.U. 1720, the Company requested a cost of service increase of $2,039,000, reflecting a five-year amortization of hurricane expenses (Exh. BE-101, p. 8). On June 1, 1986, the Company filed updated information indicating that the incremental cost of Hurricane Gloria was $10,447,000. Based on this updated information, the Company has requested an adjustment increasing cost of service by $2,089,000.

The Attorney General argues that, although the Department allowed the five-year amortization of extraordinary storm costs in both D.P.U. 19300 and D.P.U. 1720, the Department has never stated that five years is the only correct amortization period that can be applied to storm costs (Attorney General Brief, p. 32). Instead, the Attorney General supports the recommendation of Mr. Marquart for a normalized storm expense level of $1,533,000. This recommendation amounts to a $687,000 increase in the cost of service, as opposed to the Company's proposed increase of $2,090,000 for the 1984 and 1985 storms (Exh. AG-JPM-1, p. 18).

Mr. Marquart's recommendation is based on a three-year average expense level for estimated nonrecurring incremental expenses paid to entities other than BECo for the September 1985 storm. Mr. Marquart chose three years based on the frequency of the three major storms since 1977. In addition, he excluded incremental labor and management overtime costs from the

normalized storm adjustment, arguing that these costs have already been normalized by the Company through its wage and overtime adjustments (Exh. AG-JPM-1, pp. 18-20; Attorney General Brief, p. 35).

The Company argues that its treatment of these storm expenses as extraordinary, nonrecurring costs is in compliance with the Department's decision in D.P.U. 1720. The Company also contends that the Attorney General and his cost of service witness, Mr. Marquart, have confused the concepts of extraordinary nonrecurring costs and periodically recurring costs. BECo points to the Attorney General's assertion that storm costs should be set at a level which is representative of future costs. The Company argues that the rationale for allowing "recovery of extraordinary nonrecurring expense has nothing to do with representative future rate levels" (Company Brief, p. 70).

In response to the Attorney General's proposed adjustment to BECo's amortization of storm costs, the Company argues that these extraordinary costs cannot be characterized as periodic costs since there is no measure of predictability. The Company further asserts that, even if the Department were to conclude that some level of storm expense was predictable and warranted treatment as a periodically recurring expense, an additional adjustment would still be required for a storm of Gloria's magnitude (Company Brief, p. 76). Finally, the Company takes exception to the Attorney General's distinction between

incremental labor costs and incremental "outside" costs for purposes of amortization, stating that costs related to Hurricane Gloria are clearly incremental and "beyond the labor cost (normal and overtime) already in the test year" (Company Brief, p. 80).

The Attorney General responds that if the Department wishes to allow recovery of expenses associated with Hurricane Gloria, then a ten-year amortization period should be adopted (Attorney General Reply Brief, p. 18).

The Department finds that the Company's proposal regarding recovery of costs associated with Hurricane Gloria is appropriate and in accord with ratemaking standards. In D.P.U. 1720, for example, the Department held that estimated costs of $4,410,000 resulting from a post-test year storm were extraordinary and warranted an amortization period of five years. In this case, the Department is faced with another post-test year storm which has triggered costs of $10,447,000. The Department finds that the costs incurred as a result of Hurricane Gloria are nonrecurring, extraordinary and properly amortizable over a five-year period.

In addition, the Department finds that the Company is entitled to an increase in cost of service for actual March 1984 storm costs which have exceeded the costs allowed and amortized by the Department in the last rate case. In D.P.U. 1720, the Department ordered BECo to provide actual incremental costs of the 1984 storm in its next rate filing "so that the amortization amount may be appropriately adjusted." Id., p. 88.

Although the Attorney General recommends that the ongoing amortization of March 1984 storm costs and proposed amortization of Hurricane Gloria costs be replaced by a normalized storm expense, he has presented insufficient evidence in this case to support the proposal offered by Mr. Marquart. While Mr. Marquart correctly noted that three storms have been accorded amortized expense treatment in rate cases over the last nine years, his method fails to set forth any real standards for defining a major storm.

Although the Company argues that the Attorney General has confused the concepts of extraordinary nonrecurring costs and periodically recurring costs, there is no precedent which precludes the Department from characterizing an expense as recurring if there is a reliable method to measure past experience and future predictability. Ultimately, though, it is the unpredictability of both the timing and level of expenses associated with unusual storm costs that renders the process of normalizing such expenses so difficult that amortization remains the most appropriate approach.

Accordingly, we reject the Attorney General's proposed adjustment for 1984 and 1985 storm expense.

R. IMPACT 2000 House Write-off

The Company has included $392,000 in its proposed cost of service as a write-off of the IMPACT 2000 house, a Brookline property that has been used by BECo to demonstrate the uses of solar energy (Exh. AG-192, p. 1). The Company's cost of service

witness, Mr. Alpert, testified that the Company has expensed amounts in excess of $475,000 or the Company's current estimate of the property's value (Tr. 15, p. 1754).

The Attorney General argues that the write-off should be denied because there is "little reason to suppose that the Company will not receive fair market value for its IMPACT 2000 house in Brookline" (Attorney General Brief, p. 88). The Attorney General notes that an August 1985 appraisal indicated that the house, with one acre of land, had a market value of $700,000, while a January 1986 appraisal valued the house and two acres of land at $750,000 (AG-RR-29 (Supp.); Exh. AG-192). The Attorney General describes the Company's decision to write off a portion of the house either during the appraisal or before the appraisal was complete as "hasty and premature" (Attorney General Brief, p. 88).

While the Company has expressed disagreement with the Attorney General's statements, it has agreed to remove $392,000 from cost of service "with the understanding that any difference between cost and selling price will be treated in a future case when the actual selling price is known" (Company Brief, p. 193).

The Department finds that the Company's decision to write off a part of its investment in the IMPACT 2000 house at this time is inappropriate, particularly in light of recent appraisals which indicate that a potential sale may not generate a loss. Accordingly, we find that $392,000 should be removed from the Company's cost of service. In making this decision,

the Department makes no determination regarding the ratemaking treatment of any future sale of the IMPACT 2000 house.

S. IMPACT 2000 House Advertising

The Company has included $334,000 in its cost of service for "advertising efforts centered on IMPACT 2000 House with related focus on Conservation and Load Management" (Exh. AG-82).

The Attorney General argues that these advertising costs should be excluded from cost of service as a nonrecurring expense (Attorney General Brief, p. 82).

The Company's cost of service witness asserted that the $334,000 expended on IMPACT 2000 advertising during the test year is part of the Company's continuing C&LM advertising. As evidence of this commitment, Mr. Alpert pointed to the Company's current Oilybeest advertising campaign, which began in May 1985 (Tr. 15, p. 1760). The Company contends that, although there will be no future advertising of the IMPACT 2000 house, there will be other advertising efforts related to C&LM that will result in no decrease in this level of expense. Consequently, the Company concludes that the $334,000 expense is a valid recurring cost for ratemaking purposes (Company Brief, pp. 194-195).

The Company has failed to present sufficient evidence to show that the test year level of IMPACT 2000 advertising expenses is recurring and, therefore, requires inclusion in cost of service. Mr. Alpert stated that IMPACT 2000 advertising, which accounted for one-half of the Company's test year C&LM

advertising expense, will terminate after the sale of the house (Tr. 15, pp. 1759-1763). The Company has failed to present evidence to demonstrate that the IMPACT 2000 advertising is part of a continuing program of C&LM advertising or that such advertising is likely to recur at test year levels in the future.

The Company points only to its current Oilybeest campaign as evidence of its continuing commitment to C&LM advertising. Based on this record, we are not convinced that the Oilybeest campaign is a reasonable promotion of C&LM or that the costs associated with it are legitimate for ratemaking purposes. We therefore reject BECo's contention that the Oilybeest campaign demonstrates any ongoing commitment to continue C&LM advertising at test year levels.

A review of the Company's records shows that BECo expended $1,252,525 for "Informational and Instructional Advertising" (Account 909) during the test year, as opposed to $629,147 expended in the same account during the year ended June 30, 1984. This increase is primarily attributable to $334,000 spent on IMPACT 2000 advertising efforts and $383,000 for the IMPACT 2000 house write-off (Exh. AG-820). Clearly, the amounts expended on IMPACT 2000 advertising did not occur at the same level before the test year, and the Company has failed to show that similar costs will recur in the future. Accordingly, the Department finds that $334,000 of advertising expenses for the IMPACT 2000 house shall be removed from cost of service.

T. DC System Discontinuance Expenses

In Boston Edison Company, D.P.U. 748/749 (1984), the Department approved the Company's plan for retiring its direct current ("DC") distribution system. In Boston Edison Company, D.P.U. 748A/749A (1985), the Department approved the Company's retirement plan under which BECo would pay for all street work, engineering costs on private property, and program administrative costs, while sharing the cost of private property conversion work with customers.

In this case, the Company has included $1,482,000 in cost of service representing the five-year amortized cost of discontinuance of the DC system. The Company's total cost estimate of $7,410,000 comprises $750,000 for the full cost of engineering work and 50 percent of an estimated $13,320,000 for private property conversion work. The Company is not seeking amortization of street work expenses, which it plans to capitalize along with other plant. Similarly, the Company has not included administrative costs, which it plans to recover as a regular O&M expense (Exh. BE-100, p. 69; Exh. BE-101, p. 29; Exh. BE-112).

The Attorney General argues that the Company's proposal for inclusion of these post-test year expenses has no foundation in the Department's ratemaking methodology. He contends that the Company's proposed amortization is based on questionable estimates, noting that the estimate of $13,320,000 for property conversion work was predicated on input from a local electrical

contractor who had recently performed several DC conversions (Exh. HO-12). Finally, he notes that the DC conversion will confer economic benefits on BECo and, thus, the Company "mismatches revenues and expenses by estimating costs but failing to estimate benefits" (Attorney General Brief, p. 28).

The Company argues that the significant costs associated with the DC discontinuance plan are "sufficiently known and measurable to warrant an adjustment" to cost of service. The Company notes that the costs which it proposes to amortize have been approved by the Department in D.P.U. 748/749. The Company states that retirement of the DC system has already begun and cost estimates are based on reliable information (Company Brief, p. 98).

The Department finds that the Company has failed to prove that post-test year estimated costs associated with the DC discontinuance program are sufficiently known and measurable to warrant inclusion in cost of service. For example, in estimating conversion costs, the Company has assumed that property conversion costs for monthly customers will exceed conversion costs for bimonthly customers (Exh. HO-12), but the Company has failed to provide any documentation to support that assumption. Although the Department has approved the DC discontinuance program and has determined which program-related costs would be borne by the Company and which would be shared with customers, that decision rested upon principles of traditional ratemaking, i.e., setting rates on the basis of a

representative test year with expense adjustments that are known and measurable. The Company has not shown these post-test year expenses to be either known and measurable or recoverable under other Department precedent.

Accordingly, the Department finds that the Company's proposed cost of service should be reduced by $1,482,000. In disallowing this expense, the Department does not rule that the Company cannot request amortization of expenses associated with the DC discontinuance program in future rate proceedings. To the extent that such costs are known and measurable and recurring, or nonrecurring and extraordinary, we will consider their inclusion in the Company's cost of service in its next rate case.

U. Wage Adjustment

In its initial filing, the Company included an adjustment to test year wage expense of $11,711,000 in its cost of service. This amount included $4,792,000 to annualize wage and salary increases which took effect during the test year; and $7,539,000 to annualize post-test year wage increases, based on anticipated increases resulting from new union contracts expected to take effect May 16, 1986, and increases for exempt employees scheduled to take effect on September 1, 1986 (Exh. BE-101, p. 18). Finally, the Company reduced its wage adjustment by $620,000 to reflect that portion of the increase that will be billed under contracts for power sales (Exh. BE-100, p. 31; Exh. BE-101, pp. 17-18). On June 12, 1986, the Company filed updated

information based on recently approved labor agreements which increases the proposed wage adjustment by $1,790,000.

The Attorney General opposes the Company's proposed wage adjustment in three areas, adopting the recommendations of his cost of service witness, Mr. Marquart (Attorney General Brief, pp. 40-41). First, the Attorney General argues that the wage adjustment must be reduced, stating that since the September 1, 1986 increase for exempt employees will take effect two months into the "rate year," BECo is entitled only to ten-twelfths of that proposed adjustment (Exh. AG-JPM-1, p. 17). Second, the Attorney General contends that the overtime component of both test year wages and the proposed wage adjustment must be normalized. He asserts that the result of this adjustment would be to reduce cost of service by $489,000 (Exh. AG-JPM-1S, p. 41). Finally, the Attorney General recommends a further reduction in cost of service of $451,000, representing one-half of the cost of BECo's senior management incentive compensation program (id.).

1. Post-Test Year Wage Increases

The Company has increased cost of service to annualize an expected September 1, 1986 increase in the wages of nonunion employees. In support of this adjustment, the Company has presented a ten-year comparison of the wage increases for union and nonunion employees to show that the latter group has historically received the same percentage increase in wages as union employees (Exh. BE-102).

In response to the Attorney General's argument suggesting that the September 1, 1986 wage increase for nonunion employees be prorated, the Company contends that it has followed Department precedent allowing a full year's effect for those increases which occur before or early in the "rate year." The Company further argues that if such prorated treatment were to be approved by the Department, the Company should be permitted to include an allowance for expected wage increases for other pay groups during the first six months of 1987. The Company argues that a recomputation of the wage adjustment which removes two months of increase for exempt employees, but adds 1987 wage increases for other groups, would serve to increase its wage adjustment further (Exh. BE-121; Company Brief, pp. 122-123).

The Department rejects the Attorney General's proposal to prorate the estimated increase for exempt employees. In past cases, the Department has annualized those rate increases which occur within six months after the issuance of the Department's rate Order, and the Attorney General has not presented any reason to alter this rule. As we have often stated, our goal is to set rates designed to cover a representative level of future expenses. Prorating legitimate labor expenses would conflict with this goal. In addition, the Company has demonstrated that wage increases for exempt employees have historically mirrored wage increases for union groups (Exh. BE-102). Accordingly, we will allow that portion of the Company's wage adjustment attributable to the September 1, 1986 increase in the wages of exempt employees.

The Department also finds that the May 16, 1986 wage increases set forth in the Company's June 11, 1986 update constitute known and measurable post-test year changes appropriate for inclusion in cost of service. Accordingly, we shall increase cost of service by $1,790,000.

2. Overtime

The Attorney General proposes that a normalization adjustment for overtime be made to both test year wages and the Company's proposed wage adjustment. In proposing an adjustment of $489,000, the Attorney General's cost of service witness has applied a normalized three-year average overtime percentage of 11.53 percent to both test year wage expense and the wage adjustment proposed by the Company. Mr. Marquart derived his three-year overtime average from the Company's data for calendar years 1983 through 1985. The Company's overtime percentage for the test year was 11.97 percent (Exh. AG-JPM-1S, p. 13, Exh. MAG (A)-5, p. 18B; Exh. AG-157, p. 2).

The Company argues that the Pilgrim outage of 1984 was primarily responsible for the increased overtime percentage during the test year. The Company notes that the overtime associated with the Pilgrim outage was removed from test year labor expense and, ultimately, cost of service, through the Pilgrim normalizing adjustment (Exh. BE-101, p. 23). The Company therefore contends that the Attorney General's proposed adjustment to test year wage expense, in essence, double-counts overtime costs (Company Brief, pp. 126-127).

In D.P.U. 1720, the Department rejected the Attorney General's proposal for an overtime normalization adjustment. In that case, the Department found that a test year overtime percentage which exceeded the five-year overtime average percentage by .89 percent was neither abnormal nor "unrepresentative of the levels which may reasonably be expected to occur in the future." Boston Edison Company, D.P.U. 1720, pp. 55-56 (1984).

In this case, the Attorney General is proposing a reduction to the Company's wage adjustment where the test year overtime percentage exceeds the three-year average overtime percentage by only 0.4 percent. Once again, the Department finds that the variance between the Company's three-year average percentage of overtime hours worked and the test year percentage is not excessive. Accordingly, it does not warrant a finding that the overtime hours worked in the test year were so abnormal as to be unrepresentative of the levels which may reasonably be expected to occur in the future.

The Department, however, finds that the Company's cost of service treatment of incremental labor expense associated with the Pilgrim outage makes it necessary to adjust the Company's wage adjustment. The Pilgrim outage resulted in overtime wage expense of $2,305,000 (Exh. AG-83). This overtime expense was included in the per-book labor expense used to calculate the Company's wage adjustment (Exh. BE-101, p. 18; Company Brief, p. 123). Although the incremental labor expense of $2,305,000

was removed from cost of service through the Pilgrim outage normalization adjustment (Exh. BE-101, p. 23), this amount incorrectly remained in test year labor expense for the purpose of calculating the Company's wage adjustment (Exh. AG-157, p. 2).

While the level of test year overtime does not require an overtime normalization adjustment as proposed by the Attorney General, the Department still must remove that portion of the wage adjustment attributable to overtime wages that have been removed from cost of service through the outage adjustment. Accordingly, the Department finds that the Company's proposed wage adjustment should be reduced by $255,000 to reflect that portion of the wage adjustment attributable to overtime expenses associated with the Pilgrim outage. 14/

3. Senior Management Incentive Compensation Program

During the test year, the Company expended $944,000 attributable to BECo's senior management incentive compensation program ("SMICP") (Exh. AG-49). The Attorney General proposes that test year wage expenses be reduced by $451,000, representing 50 percent of $902,000, or that portion of the SMICP expense charged to O&M expense, so as to share the expense

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14/ The Department calculates the $255,000 reduction in the wage adjustment by taking the electric portion of Pilgrim overtime expense, $2,226,000, as a percentage of electric labor expense, $118,006,000, and applying that percentage to the Company's proposed wage adjustment of $14,215,000 (Exh. BE-101 (Updated), p. 18; Exh. AG-83). The resulting figure is then reduced by 5.02 percent, representing the Company's allocation to power contracts (Exh. BE-101, p. 19).

of the SMICP between shareholders and ratepayers. The Attorney General proposes an additional adjustment of $89,000 to account for that portion of the SMICP expense which has been factored into the wage adjustment (Attorney General Brief, pp. 41, 44-45; Exh. AG-JPM-1S, pp. 14-15, Exh. MAG (A)-5, p. 18B).

The Company contends that SMICP benefits customers through its control of O&M expense. Mr. Alpert noted that the program emphasizes earnings per share, which has a direct relationship to maintaining a reasonable cost of service (Exh. BE-124, p. 17). The Company also states that the SMICP is a required cost of compensating its employees and, in particular, part of the cost of attracting and retaining good executives. The Company maintains that the SMICP ultimately benefits customers through a well-managed, financially strong business (Company Brief, p. 127).

Based on our review of the performance of the Company's senior management, we are unable to find that the SMICP has been successful in obtaining managers capable of providing the type of leadership necessary to maintain a financially strong company providing quality service. Further, in light of our conclusions in Section II, above, we cannot find that this program has in any way contributed to actions on the part of management that reinforce the Company's public service obligation. Rather, as we have found above, there are strong indications that management is not carrying out this obligation to the extent the public has the right to expect.

Accordingly, the Department will remove $827,000 of test year SMICP costs allocated to O&M expense from cost of service.[15/] The Department also finds that an additional $100,000[16/] must be removed from cost of service, representing that portion of the Company's wage adjustment attributable to SMICP expenses.

V. FICA Taxes

The Company has included $675,000 in its cost of service for the increase in FICA payroll taxes resulting from its wage adjustment (Exh. BE-101 (Updated), p. 36).

The Attorney General contends that the FICA taxes must be reduced by $56,000, based on Mr. Marquart's calculation of a "proper wage adjustment" (Attorney General Brief, p. 45). The Company counters that, since a wage adjustment is not appropriate, an adjustment to FICA taxes is not warranted (Company Brief, p. 129).

The Department finds that adjustments to BECo's FICA taxes are warranted in light of other wage adjustments ordered in Section IV.U to (a) reduce test year wages for the SMICP, and

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15/ The adjustment of $827,000 for test year SMICP expenses accounts for allocations to both steam (3.44 percent) and power contracts (5.02 percent) (Exh. BE-101, pp. 18-19).

16/ The Department calculates the $100,000 reduction in the wage adjustment attributable to disallowed SMICP expense by taking that portion of SMICP expense allocated to operation and maintenance, $871,000, as a percentage of electric labor expense, $118,006,000, and applying that percentage to the Company's proposed wage adjustment of $14,215,000 (Exh. BE-101 (Updated), p. 18; Exh. HO-113). The resulting figure is then reduced by 5.02 percent, representing the Company's allocation to power contracts (Exh. BE-101, p. 19).

(b) reduce the Company's proposed wage adjustment by that portion attributable to overtime expenses associated with the Pilgrim outage and SMICP expenses.

We therefore find that FICA taxes, as set forth in the Company's updated information, must be reduced by $72,000, as shown in the following calculation:

D.P.U. reduction to wage adjustment........	355,000
D.P.U. adjustment for SMICP................	827,000
Total wage reduction for purposes of FICA calculation..........................	$1,182,000
Pro forma BECo FICA tax expense............	8,379,000
Pro forma BECo 1986 FICA wage expense.....	136,933,000
FICA tax as % of payroll...................	6.12%
D.P.U. reduction to FICA tax increase (6.12% X $1,182,000).....................	$72,000

Therefore, the Department will allow a FICA tax expense of $8,518,000, or a reduction of $13,000 from the FICA tax expense of $8,531,000 originally filed by the Company.

W. Property Tax Abatements

The Company has reduced its test year property tax expense[17/] by $3,349,000[18/] for abatements received during and after the test year. This amount consists of (1) $925,000

17/ The Company included property taxes of $61,077,000 in its initial cost of service filing (Exh. BE-101, p. 36). The Company's revised filing included property taxes of $63,449,000 (Exh. BE-101 (Updated), p. 36). A further revised filing, received June 24, 1986, included property taxes of $57,445,000 (Exh. BE-101, (Second Update), p. 36).

18/ The Company's initial filing included tax abatements of $3,400,000, but this amount has been corrected to $3,349,000 (Exh. BE-124, pp. 21-22).

for fifteen abatements received during the test year; (2) $2,034,000, representing a five-year amortization of tax abatements of $10,170,000 received during the test year from Somerville, Watertown and Quincy; and (3) $390,000, representing a five-year amortization of a $1,950,000 tax abatement received from the Town of Watertown after the test year.

The City argues that consistency with Department precedent requires that the full, unamortized amount of property tax abatements be flowed through to ratepayers. The City also contends that the Company has failed to accord consistent accounting treatment to various abatements, arguing that the Department should require that all post-test year abatements which the Company has received be included in the cost of service (City Brief, p. 25).

The Attorney General supports the City's position regarding property tax abatements (Attorney General Reply Brief, p. 23). In addition, he urges the Department "to give strong consideration to making its first priority on this issue the returning of test year abatement dollars back to the ratepayer as quickly as possible" (id., p. 25).

The Company contends that its treatment of property tax abatements is in complete compliance with Department precedent. BECo notes that the abatements of $10,170,000 received from three municipalities during the test year amount to approximately 15.8 percent of total property tax expense. The Company contends that inclusion of that entire amount for

ratemaking purposes would distort test year property tax expense and "that such an abatement level is in excess of what the Department has defined as distortion in past orders" (Company Brief, p. 218). Similarly, the Company argues that the post-test year Watertown abatement of $1,950,000 is extraordinary and warrants inclusion in cost of service on an amortized basis (id., p. 221).

The Department has consistently held that tax abatements received within the test year are to be treated on a cash basis to reduce property tax expense in the cost of service, except where a flow-through of the entire abatement would result in a distortion of test year property tax figures. Boston Edison Company, D.P.U. 19991, pp. 31-32 (1979); Manchester Electric Company, D.P.U. 20113, p. 9 (1980). The Department has also placed the burden upon the Company to show that a distortion will result from inclusion of the entire amount of the abatement. Boston Edison Company, D.P.U. 1350, pp. 126-127 (1983). Here, the Company has shown that the test year abatements from three municipalities represent 15.8 percent of total property tax expense. The Department finds that reducing property tax expense by the full amount of these abatements would unduly distort test year property tax expense. Accordingly, consistent with our past decisions, we allow the test year abatements of $10,170,000 to be amortized over a five-year period.

Abatements received after the test year are not reflected in the cost of service unless they are extraordinary in amount. See Boston Edison Company, D.P.U. 1720, p. 80 (1984); Massachusetts Electric Company, D.P.U. 800, p. 43 (1982); Manchester Electric Company, D.P.U. 20113 (1980). The Department finds that the Watertown tax abatement of $1,950,000 is large enough to require inclusion in the cost of service. Since the inclusion of the full amount of the post-test year Watertown abatement would distort test year property tax expense, we find that the extraordinary nature of this abatement warrants amortization over a five-year period.

Accordingly, the Department rejects the adjustments to property tax expense proposed by the City and the Attorney General and accepts the treatment proposed by the Company.

X. City of Boston Settlement Write-offs

The Company has included $393,000 in cost of service for City of Boston municipal bills and an interest amount which had been written off as uncollectible after an early 1984 settlement agreement between the Company and the City (Exh. AG-112). The Attorney General argues that this amount had been mistakenly booked to "Office Supplies and Expenses" (Account 903). The Company agrees that cost of service should be adjusted by $393,000 (Company Brief, p. 171).

Accordingly, the Department finds that cost of service shall be reduced by $393,000.

Y. CATV Revenues

The Company had originally proposed an increase of $317,000 to cable television ("CATV") pole attachment revenues (Exh. BE-101, p. 55). Mr. Alpert testified that this adjustment was incorrect, stating that, in arriving at its adjustment in this proceeding, the Company incorrectly increased test year CATV revenue by annual CATV revenue, as opposed to increasing test year revenue by that revenue resulting from attachments added between July 1, 1985, and December 31, 1985. In its amended adjustment to CATV revenues, BECo stated that the correct increment for that period is approximately $1,000 (Exh. BE-115, p. 2). The Attorney General's cost of service witness, Mr. Marquart, concurred in this correction (Exh. AG-JPM-1, p. 32).

In Boston Edison Company, D.P.U. 1720, p. 85 (1984), the Company was required to adjust test year revenue to reflect "the most recent number of poles to which CATV attachments have been made." We find that the $1,000 adjustment now proposed by the Company does not comport with the Department's precedent. During the first quarter of 1986, the Company commenced billing for CATV pole attachments in three additional communities. The annual revenue from the new attachments in Holliston, Norfolk and Sudbury will amount to approximately $48,000 (HO-RR-21). This amount has not been included by the Company in its adjustment to CATV revenue. Since these amounts are known and measurable, we will increase the Company's proposed adjustment to test year CATV revenues by $48,000 to reflect the known and

measurable change in revenues attributable to CATV pole attachments.

7. Depreciation

The Company has adopted the average remaining life method to determine its depreciation charges. Boston Edison Company, D.P.U. 1350, p. 110 (1983). Application of the average remaining life method requires that investment in depreciable property be determined, accrued depreciation to date be subtracted, and the estimated net salvage value (estimated salvage value minus cost of removal) be subtracted to establish a composite annual depreciation charge to be applied over the estimated average remaining life of the assets in each plant account. Remaining life accrual rates are designed to allow adjustments to depreciation rates in a manner ensuring that the entire investment, including any previous under- or over-accruals, is recovered during the asset's anticipated remaining life.

In D.P.U. 1720, pp. 41-45 (1984), the Company, through its witness Mr. Faust, provided an update of a depreciation study presented in D.P.U. 1350. The Department approved the revised accrual rates for the Company's production plant presented in Mr. Faust's revised study.

In this case, Mr. Faust has presented a further update to his depreciation study, once again setting new accrual rates for the Company's production plant. Pursuant to Mr. Faust's study,

the Company proposes the following revised accrual rates (Exh. BE-500, p. 13):

Steam Production Plant	3.87%
Nuclear Production Plant	3.78%
Other Production Plant	4.59%
Total Production Plant	3.84%

No party opposed the depreciation study.

The Department finds that the Company's proposed depreciation expense, based on accrual rates set forth by Mr. Faust, is appropriate. The expense will be adjusted only to the extent necessary to correspond to specific rate base adjustments discussed elsewhere in this Order.

AA. Taxes

Three different tax issues are in dispute in this proceeding: (1) an adjustment for depreciation that is not tax-deductible on pre-1954 assets; (2) the existence of a surplus in the Company's deferred tax reserve; and (3) an adjustment for a special property tax deduction.

1. Pre-1954 Asset Adjustment

In its tax calculations, the Company has included an income tax adjustment of $3,382,000 for pre-1954 assets which are fully depreciated for tax purposes, but are still being depreciated for ratemaking purposes (Exh. BE-100, pp. 73-74; Exh. BE-101, p. 42). The Company asserts that an adjustment to income taxes is necessary because the assets continue to be depreciated for ratemaking purposes since they are still in service and are used

and useful. The difference in the calculation of the depreciation expense allowable for tax purposes and the calculation of depreciation expense allowable for ratemaking purposes creates a timing difference for calculating and recognizing income for the Company. This timing difference is usually accounted for by setting aside funds in a deferred tax account as items enter service. The reserve provides funds to pay the higher taxes expected in the future when the tax benefit of the depreciation expense for those assets has expired and the deduction is no longer available for tax purposes, but the depreciation expense is still permitted for ratemaking purposes. In this fashion, the timing differences between tax depreciation and ratemaking depreciation are normalized.

The Company asserts that the timing differences for those assets acquired before 1954 have not been fully normalized except for the years 1974 and 1975 (Tr. 23, p. 3120). Therefore, according to the Company, sufficient funds have not been set aside in the deferred income tax account to pay for this tax expense (Company Brief, pp. 203-204).

The Attorney General opposes the Company's proposed adjustment, arguing that the pre-1954 assets have been fully depreciated for both tax and ratemaking purposes. Mr. Marquart testified that to the extent that pre-1954 assets began to depreciate on January 1, 1954, and the Company applied its book depreciation rates, all assets would be fully depreciated by July 1, 1986 (Exh. AG-JWM-1(S), pp. 34-37). The Attorney General asserts that the Company has failed to identify pre-1954

assets on its books which are not fully depreciated and to support its contention that an additional adjustment is needed. The Attorney General states that the adjustment could be justified under the remaining life method adopted by the Company in D.P.U. 1350 but that the method was instituted too recently to apply to these assets (Attorney General Brief, pp. 92-98).

The Company charges that Mr. Marquart's analysis fails to consider the effect of premature retirements on the depreciation recovery period of a group of assets. Mr. Alpert testified that the effect of early retirements requires the extension of the depreciation recovery period beyond the average life of the asset group (Company Brief, p. 204). BECo asserts that the three key points are: (1) the assets are still used and useful and depreciated for ratemaking purposes under the composite method of depreciation; (2) tax/book differences were not fully normalized in the past so no provision for deferred taxes was made; and (3) the accumulated deferred tax reserve is deficient and cannot pay these taxes.

The Company is correct that the assets are still used and useful, the assets are being depreciated for ratemaking purposes, and no provision for deferred taxes to account fully for this specific tax/book timing difference was ever made. Accordingly, we find the Company's proposed adjustment to be appropriate.

2. Accumulated Deferred Income Taxes

In D.P.U. 1720, the Department ordered the Company to document the effect of the 1979 reduction in the federal

corporate tax rate from 48 percent to 46 percent on its income tax liabilities and the reserve for deferred income taxes. D.P.U. 1720, p. 33. The Company did not address the issue of the tax change in its prefiled testimony, but in response to a Bench request, the Company submitted a calculation of the estimated surplus resulting from the change in the federal tax rate from 48 percent to 46 percent (HO-RR-44).

The Company did claim an overall net deficit in its reserve for deferred taxes resulting from numerous timing differences, including the change in tax rates (Exh. BE-100, pp. 85-87). Mr. Alpert stated that the Company saw no real need to adjust the reserve, claiming that "the reserve is not that far from where it might be" (Tr. 25, p. 3378).

The Attorney General asks the Department to keep this issue open until the next rate case because of the lack of information filed by the Company and the potential change in the federal tax rate (Attorney General Brief, pp. 98-99).

The Company argues that the calculations provided demonstrate that a deficit exists in the reserve for deferred taxes if all timing differences are taken into account, not just the decrease in the tax rate (Company Brief, pp. 211-212).

We find it appropriate to explore more fully the issue of whether there is a surplus or deficit in the accumulated deferred tax reserve. We again direct the Company in its next rate filing to provide detailed information as part of its prefiled testimony and schedules.

First, the Department directs the Company to file a calculation of the surplus or deficit created solely by changes in tax rates. Second, the Company is directed to submit a calculation of the overall surplus or deficit in the reserve for deferred taxes, with a complete explanation of the method used to perform the calculation. The Company should also fully explain the reasons for the existence of the surplus or deficit, the items comprised in the surplus or deficit and the extent to which deferred taxes have been accumulated.

For each of the above schedules, the Company should fully explain any adjustments included therein and also provide a proposal to adjust the reserve account and amortize any surplus or deficit. The Company should also address any potential conflict with tax laws and Internal Revenue Service ("IRS") regulations that could result from an adjustment of the deferred tax account.

3. <u>Special Property Tax Deduction</u>

In April 1984, the Company received permission to change its tax accounting of property tax expenses and to deduct an additional $35,301,000 in municipal property taxes over a ten-year period beginning in 1982 (Exh. BE-100, p. 77; Exh. BE-101, p. 7, l. 16). The IRS approved the Company's change to the accrual method of reporting property taxes. As a result, the property tax payments due on May 1, 1982, which should have been reported on the 1981 return under the new accrual method but would have been reported on the 1982 return

under the old method, were ineligible for inclusion in either year. To allow the Company to deduct the additional property tax expense and reduce its income tax liability, the IRS allowed the Company to spread the deduction over ten years (Tr. 10, pp. 1245-1263). BECo decided to flow through the reduction in tax liability to ratepayers rather than normalize the effects of the timing difference because the difference is a permanent difference which is not expected to reverse on the Company's books (Exh. BE-100, p. 77). The proposed adjustment decreases cost of service by $4,889,000.

The Attorney General opposes the adjustment, anticipating that property taxes will decrease significantly under the Company's pending suit for tax abatement against the City of Boston (Attorney General Brief, pp. 99-101). The Company estimates that taxes will drop by $15 million to $20 million per year if the suit is successful (Tr. 25, pp. 3134-3135). According to the Company, if taxes were to decrease by that magnitude, the Company's income taxes would increase significantly and a new rate case might be necessary (Company Brief, p. 214).

The Company states that the appropriate treatment of the deduction depends on the expectation of the future level of property tax expense; BECo expresses a "willingness to accede to the Department's wishes on this issue" (Company Brief, p. 215).

Although we recognize that the outcome of the pending litigation could affect the later treatment of this adjustment,

it would be inappropriate to tie our decision to the uncertain outcome of that case. Accordingly, we find the Company's adjustment to be appropriate.

BB. Revenue Annualization Adjustment

Through discovery, the Attorney General became aware of the existence of an internal Company publication known as the management news summary (Exh. AG-70). This weekly publication contains information on a variety of topics, such as overtime statistics, plant outages, future capacity additions and sales information. The information on new load additions includes projected annual revenues for both individual projects such as Copley Place and aggregate groups of residential customers in different areas. The Attorney General used the figures contained in the weekly news summaries to derive a revenue annualization adjustment of $2,787,000 in additional revenues for sales growth during the test year (Exh. AG-JPM-1(S), p. 28; Exh. AG-JPM-2(S), (A)-7, p. 2). The adjustment attempts to adjust test year revenues to recognize the expected post-test year revenue impact of customers who were not on line for a full year during the test year, but would be in the future. By increasing revenues, the Attorney General claims that the proposed adjustment would reduce any deficiency in funds provided by ratepayers to meet the costs incurred by the Company in providing service.

The Attorney General asserts that his proposed adjustment is a conservative estimate of additional revenues which the Company

can expect from ratepayers since it includes only a portion of estimated revenues from projects approved during the test year and only 25 percent of the revenue projected for those projects. He defends the adjustment as a necessary recognition of growth-related revenue. Acknowledging the Department's precedent in Boston Edison Company, D.P.U. 160 (1980), which prohibited year-end customer revenue adjustments, the Attorney General argues that the proposed adjustment does not depend on a future occurrence, but on the Company's revenue expectations of projects approved during the test year (Attorney General Brief, pp. 90-91).

The Company opposes the Attorney General's adjustment, attacking both the figures on which the adjustment was based and the theory behind the adjustment. The Company states that Mr. Marquart did not correctly interpret the sales figures in the news summaries and so did not correctly recognize which customers would be on line during the test year (Company Brief, pp. 197-199). BECo argues that a forecast is the best measure of increased revenue level and that the Company's most recent load forecast predicts relatively low overall growth rates. As the Company contests the basis on which the proposed adjustment was calculated, so the Company opposes the adjustment as insufficient to meet the known and measurable standard for post-test year adjustments.

The Company also opposes the adjustment based on established Department precedent. Arguing that previous post-test year

sales adjustments were allowed only when a large revenue-producing addition was made to rate base, the Company cites several cases where the Department has rejected year-end customer adjustments as defeating the use of an inflation adjustment and year-end rate base to mitigate attrition and regulatory lag (Company Brief, pp. 199-201).

In a number of past decisions, the Department has rejected proposals to alter test year revenues to reflect anticipated changes in sales experienced by companies. See, e.g., Eastern Edison Company, D.P.U. 1580, pp. 35-43 (1984); Boston Edison Company, D.P.U. 906, pp. 79-81 (1982). Here, too, we reject the Attorney General's proposed adjustment since it fails to meet the Department's known and measurable standard. For instance, Mr. Marquart was uncertain of potential duplication in the categories of figures on which he based his calculation (Tr. 21, pp. 2802-2803). The Attorney General admits the calculation is imprecise, but asserts that the adjustment is "conservative".

> The mechanisms of this adjustment were forced upon Mr. Marquart - forced by BECo's refusal to disgorge information that only the Company could supply - but would not. Using the only Company-generated information available, Mr. Marquart compensates for the acknowledged "roughness" of the methodology by adopting the ultra-conservative approach of, first, taking only a portion of estimated revenues from projects approved during the test-year and then taking only 25% of BECo's own expected revenue to be generated (Attorney General Brief, p. 91).

This admission demonstrates the inherent uncertainty of such adjustments. We also note that the adjustment is more consistent with a future test year approach to setting rates, a

concept that has been consistently rejected by the Department. Eastern Edison Company, D.P.U. 1580, pp. 11-22 (1984).

We respond to the Attorney General's request that the proposed revenue annualization adjustment be considered in conjunction with the inflation allowance by noting that we have addressed his concerns in our discussion in Section IV.E, *supra*. To reiterate, we note that the Attorney General is correct in stating that the Department's policy of basing rates on a test year cost of service is premised on the assumption that historical data for both expenses and sales provide an appropriate matching of costs and revenues. For this reason, the Department denies proposed adjustments to test year levels unless they meet the known and measurable standard. We find that the Attorney General's proposal fails to meet this standard and that no corresponding adjustment to the Company's revenue calculation is appropriate.

V. CONSERVATION AND LOAD MANAGEMENT

A. Introduction

The Company included no specific proposals regarding conservation and load management ("C&LM") in its rate filing. BECo's test year C&LM expenses are limited to advertising featuring the IMPACT 2000 house (Section IV.S, supra).

BHA has challenged the level of the Company's commitment to C&LM in this proceeding. BECo's C&LM efforts have also been at issue in two other Department dockets. In D.P.U. 85-252, a conservation contracting program filed in response to directives specified in D.P.U. 1720, pp. 221-224, is currently under review. In addition to that program, the Company has proposed six pilot C&LM programs for approval, docketed in D.P.U. 85-266 and incorporated into the present proceeding after a motion for inclusion by the Attorney General on January 6, 1986. On May 29, 1986, the Department issued an Order addressing the Company's proposal.

The Order addressed the Company's request for the Department to approve the six C&LM programs. The Company's request revealed a mischaracterization of two key points of the Department's Order in D.P.U. 1720 regarding C&LM, namely, the Company's responsibilities for C&LM programs and the applicable cost recovery standard. In the Order, we concluded that the cost recovery rules as defined herein and in D.P.U. 1720 shall be applicable to any company-administered C&LM program. We also reiterated our longstanding policy of declining to pre-approve

programs except where it has been shown that a company has failed to pursue a reasonable course of action in meeting its responsibility to provide least-cost service. Interim Order, pp. 3-5.

B. Parties' Positions

1. Boston Housing Authority

BHA proposes that the Company fund three C&LM programs on BHA properties. BHA maintains that its three C&LM proposals are cost-effective, focused on saving electricity, based on well-established and proven technologies and acceptable to the customer. BHA argues that Company funding of its three C&LM programs would help meet near-term and mid-term future load growth in the Boston area. It states that load growth in the Company's service territory has outstripped both the Company's local sources of generation and its construction of transmission ties to the rest of NEPOOL (BHA Brief, pp. 4-5).

BHA also argues that the Company's supply and demand planning process is biased against C&LM through its continued use of impermissible cost-benefit criteria. BHA specifically contends that the use of a "revenue loss adjustment" in the Company's cost-benefit criteria for C&LM programs amounts to a type of "no-losers" test, which it asserts was rejected by the Department in D.P.U. 1720. BHA believes that this shows that BECo has "steadfastly refused to evaluate conservation and load management options in accordance with the Department's Orders" (BHA Brief, pp. 7-9).

BHA contends that the Company has refused, and continues to refuse, to purchase all cost-effective C&LM available to it. In support of this point, BHA points to the Company witnesses' admissions that the Company will not go forward with such programs until the Department assures BECo of cost recovery (Tr. 5, pp. 597-598, 627-628, 633; Tr. 15, pp. 1669-1670). BHA further argues that, to date, the Company's response to the Department's statements of relevant principles and guidelines in D.P.U. 1720 and D.P.U. 1720-C has been "...inaction, combined with feigned 'confusion,' coupled with endless requests for further 'guidance'" (BHA Brief, p. 10).

BHA maintains that the Department has, in past decisions, very clearly delineated the respective duties and responsibilities of investor-owned electric utilities and the Department itself in the Massachusetts regulatory scheme. In addition, BHA argues that it is the obligation and responsibility of every investor-owned electric utility in Massachusetts to provide a least-cost supply of electricity, subject to reliability considerations. BHA contends that the Company's position constitutes a violation of its franchise obligation to provide least-cost service (BHA Brief, pp. 9-12).

BHA would, for these reasons, have the Department order the Company to: (1) purchase all cost-effective C&LM, including BHA's current proposed programs, and (2) cease its use of the "revenue loss adjustment" in measuring the cost-effectiveness of C&LM measures. In addition, BHA urges the Department to find

that the Company has violated its service obligation regarding C&LM investments and that it has intentionally violated Department Orders. BHA asserts that, based on those findings, the Department should penalize the Company by no less than one percent on its allowed rate of return on common equity.

2. The Attorney General

The Attorney General supports BHA's position that the Company has failed to implement meaningful conservation measures (Attorney General Reply Brief, pp. 26-27).

3. The Company

The Company takes the position that its pursuit of C&LM programs has been appropriate. It interprets the Department's Orders in D.P.U. 1720 and D.P.U. 84-194 as essentially forbidding the Company from freely pursuing load management and conservation measures (Company Brief, pp. 230, 235).

In its filing in D.P.U. 85-266 the Company stated that:

> [t]he Department's Order in the Company's last rate case, D.P.U. 1720, required the Company to implement a contractor program to the apparent exclusion of any other conservation and load management programs.... In light of the D.P.U. 1720 order, however, the Company can proceed only if the Department makes it clear that in the Department's view conservation and load management programs of the sort proposed by the Company in this filing are appropriate for the Company to undertake (D.P.U. 85-266, Cover Letter, p. 2).

In response to questions by BHA, Mr. Alpert restated the Company's interpretation of the Department's policy on the appropriateness of investing in C&LM programs as a request for assurance that the Department will allow recovery, on a historical test year basis, of prudently-incurred costs for

Company-run C&LM programs (Tr. 5, pp. 597-598, 627-628; Tr. 15, pp. 1669-1670).

The Company also argues that, based on D.P.U. 1720, it has reason to believe that prudent investments in C&LM will not be recovered in rates. Based on this uncertainty, Mr. Alpert stated that, until the ground rules for cost recovery are explained by the Department, the Company will follow a policy of not making investments in generation expansion or in conservation and load management (Tr. 5, p. 633). The Company concludes that "...the central issue in this area...[is] whether under Massachusetts regulation an electric utility is intended to or even permitted to directly pursue significant conservation and load management programs on its own" (Company Reply Brief, p. 35).

The Company disagrees with BHA's contention that its cost-benefit method constitutes a no-losers test. The Company argues lost base revenues resulting from C&LM activity constitute an appropriate cost for inclusion in its cost-benefit analysis. It suggests that any reduction in sales resulting from C&LM programs has a direct effect on base revenues and should, therefore, be considered a cost of C&LM (Company Brief, pp. 236-237).

In addition, the Company argues that two points need to be resolved by the Department before it can rule on the appropriateness of adopting the BHA conservation programs. First, it contends that the Department needs to determine whether direct utility involvement in such programs is appropriate.

Second, the Company suggests that, if the Company is to undertake such a program directly, there is a need for the BHA programs to be reviewed and ranked in comparison to other programs available throughout the Company's service territory (Company Brief, pp. 240-241).

C. Analysis and Findings

There are two basic issues before us: first, whether the Department's Orders on the issue of C&LM investment support the Company's contention that it has been precluded by the Department from instituting C&LM programs; and, second, whether the Company's activities in the area of conservation and load management constitute a failure to fulfill its service obligation to provide least-cost service. In order to review the Company's specific argument that the Department has precluded it from C&LM investments and BHA's larger question of the Company's service obligation, we find it necessary to review the Department's past Orders dealing with the Company's C&LM investments, in addition to the record of this proceeding.

1. Review of Recent Orders

The Department's policies, goals and objectives regarding C&LM have evolved in a series of Orders beginning with its decision in Boston Edison Company, D.P.U. 906 (1982).

In D.P.U. 906, a request for a general rate increase, the Company proposed depreciation and amortization expense treatment for its investment in the cancelled Pilgrim 2 nuclear power plant project. In that proceeding the Department addressed the ability

of BECo to meet its service obligation to supply adequate power at reasonable cost, while reducing its dependence on foreign oil. The Department's investigation revealed that the Company was not studying the possibility of providing C&LM programs as an alternative to traditional generation options for meeting future power supply needs. The Department stated in its Order that "[c]onservation is clearly one partial answer to the question of the Company's future generation supply," and ordered the Company to submit a plan for a comprehensive program of conservation and load management. D.P.U. 906, pp. 251-252.

In its next general rate case, D.P.U. 1350 (1983), BECo requested an adjustment to its test year level of C&LM expenditures. The requested adjustment represented the costs associated with the Company's IMPACT 2000 C&LM programs implemented after the test year as a result of the Department's Order in D.P.U. 906. In its review of the IMPACT 2000 C&LM programs, the Department found it necessary to reiterate its requirement that a company's long-term planning process should give as much consideration to conservation and load management as to energy supply alternatives. D.P.U. 1350, p. 135. Also see Western Massachusetts Electric Company, D.P.U. 1300 (1983); Fitchburg Gas and Electric Light Company, D.P.U. 1270/1414 (1983); Boston Edison Company, D.P.U. 19494 (1981). The Department determined that it was necessary to provide additional guidance to the Company because the Company supplied no support or justification for its proposed C&LM programs to demonstrate that they had been selected on the basis of appropriate criteria.

In D.P.U. 1350 the Department listed five principles governing C&LM:

(1) conservation and load management programs must undergo the same analytical evaluation as supply investments;

(2) to determine the optimal mix of conservation, load management, and power supply, companies must establish a set of criteria to guide their decisions;

(3) in order for a company to demonstrate that the level of investment in conservation and load management is the result of considered integration of demand and supply options, it must consider: various estimates of conservation on long-run forecasts; estimates of costs of various supply and demand options; the impact of selected levels of conservation and load management investments; and the sensitivity of decisions to load growth and specific economic factors;

(4) conservation and load management expenditures must be shown to be prudently incurred and must be known and measurable to be included in rates; and

(5) the Department's established ratemaking principles would be applied to the recovery of conservation and load management expenditures. D.P.U. 1350, pp. 135-139.

Using the above criteria, the Department analyzed the Company's C&LM programs and made the following findings. First, the Company had not shown that its estimated costs represented a known and measurable change to its cost of service. Second, the Company did not support its level of investment with evidence that C&LM had been integrated into its long-term planning process. Third, the Company did not show that the programs it had selected to implement met any test of cost-effectiveness consistent with its responsibility to provide service at the lowest cost possible. Specifically, the Department noted its concern about the fact that the Company's proposed programs were designed to reduce its customers' consumption of oil and natural

gas as opposed to electricity. The Department, however, found that the Company had shown that its test year expense for C&LM was representative of a future level of expense and included this amount in its cost of service for ratemaking purposes. D.P.U. 1350, pp. 139-140.

The Company, in its next general rate case, D.P.U. 1720, insisted that it needed further clarification of the Department's Order in D.P.U. 1350. It took the position that further discussion of the D.P.U. 1350 standards was warranted in the hope that the Department would clarify and change the criteria established in that proceeding. In response to the Company's assertion of confusion before D.P.U. 1720, the Department developed two clarifications of the principles and standards of D.P.U. 1350. First, the Department placed the principles of D.P.U. 1350 in the context of the goals and objectives of C&LM investments. Second, the Department attempted to create an alternative structure which would give the Company the incentive to develop C&LM on a competitive basis. The Department's approach sought to clarify further and expand the options available to the Company to fulfill its service obligation to provide least-cost service.

In that Order the Department refined its criteria for C&LM investment to three basic principles:

> First, utilities must recognize that demand management strategies [or C&LM] are equal in importance to generation options in meeting customers' needs for electric service. Second, a company must integrate C&LM and capacity options in its long-run planning process.... Third, demand management and supply options must be analyzed and selected using the same criteria.... D.P.U. 1720, p. 199.

[illegible] indicated further that any test of cost-effectiveness should be "consistent with [the company's] responsibility to provide service at the lowest cost possible." D.P.U. 1720, p. 199, citing D.P.U. 1350, p. 139.

The Department then stated that its standard for review of demand management investment is the same as its standard for review of generation planning decisions, <u>i.e.</u>, utilities should invest in conservation, load management and generation options to the extent that they are cost-effective. D.P.U. 1720, pp. 200-201. The Department added that cost-effectiveness should be defined in terms of a utility's obligation to provide service at the lowest cost possible.

> The Department's objectives designed to meet this goal are equally straightforward: (1) that a utility implement C&LM programs and generation options that result in the lowest possible total cost of service in meeting customers' electrical needs, (2) that a utility use the marginal cost of providing service as a measure of cost-effective investments, (3) that a company implement C&LM programs designed to save electricity rather than to subsidize the saving of oil and natural gas, and (4) that cost recovery for C&LM investments be based on the value of the energy and/or capacity saved. D.P.U. 1720, p. 201.

The Department's goals and objectives for C&LM investment established demand planning options on an equal footing with traditional generation options.

Regarding the Company's C&LM programs before D.P.U. 1720, the Department found that the Company planned to go forward with new C&LM programs and increased expenses with no clear criteria for how those programs should be selected or what level of investment

would be appropriate. The Department further noted that the Company seemed to recognize that its programs which focused on saving oil and natural gas were not consistent with the principles set forth in D.P.U. 1350, but that the Company was willing to continue them for the purpose of maintaining a conservation ethic as long as the Department allowed cost recovery. D.P.U. 1720, p. 214.

The Department stated that it was not the amount of C&LM expenses that was of concern, but rather the direction and underlying support for those expenses. D.P.U. 1720, pp. 214-215. The Department found that many of the Company's C&LM programs violated its third objective for C&LM investment, i.e., that an electric company implement C&LM programs designed to save electricity rather than to subsidize the saving of oil and natural gas. In addition, the Department's analysis revealed that the Company did not provide an acceptable measure of its C&LM program's cost-effectiveness and thus failed to comply with both the Department's C&LM investment criteria initiated in D.P.U. 1350 and its second objective, i.e., that a utility use the marginal cost of providing service as a measure of cost-effective investments. For the above reasons, the Department ordered that all existing noncost-effective C&LM programs should be discontinued in a time frame that allowed the Company to meet its obligations to provide services that were then advertised, but that it should not extend the availability of programs that were not cost-effective. D.P.U. 1720, pp. 216-223.

In addition, the Department directed BECo to implement a pilot conservation contracting program based on the principle that the Company establish a price which it will pay for all demonstrated KWH saved. D.P.U. 1720, pp. 216-223. The price to be paid for measured KWH savings was to be less than or equal to the Company's marginal cost and should take into account the Company's short-run marginal energy costs and long-run marginal capacity costs. In describing the framework of the program, the Department directed the Company to select a target group of customers eligible to receive the electricity C&LM measures and to select through a competitive bidding process one or more conservation service companies willing to finance, install and monitor the C&LM measures that are cost-effective under the price per KWH negotiated with the Company. The Department also gave the Company the option of taking on the role of a contractor by forming a subsidiary to participate in the competitive bidding process.

In directing the implementation of the pilot program, the Department provided the Company with an alternative C&LM investment strategy. The development of this second means for carrying out cost-effective C&LM investment offered the Company greater flexibility of choice in the provision of its service obligation. The alternative structure for encouraging C&LM investments was established in the hope that it would result in the more rapid introduction of C&LM programs into the Company's service territory. The Company, professing confusion,

had for many years been unwilling or unable to comply with the Department's mandate to integrate C&LM options into its supply planning process and implement C&LM programs in a manner which could be demonstrated to be cost-effective. This situation continued despite repeated efforts on the part of the Department to address concerns raised by the Company. The alternative of a competition-based C&LM system offered the potential to attract other vendors into the area and attempted to entice the Company into a greater commitment to C&LM strategies by offering the potential of an unregulated rate of return to a Company subsidiary competing with contractors for the opportunity to install cost-effective C&LM measures, consistent with the Department's stated objectives, in the Company's service territory. Meanwhile, the Company continued to have the option of providing Company-run C&LM programs.

In Western Massachusetts Electric Company, D.P.U. 84-25 (1984), the Department made similar findings and directives concerning C&LM. In addition, the Department confirmed the standards for C&LM investment developed in D.P.U. 1300, D.P.U. 1350 and D.P.U. 1720. D.P.U. 84-25, pp. 221-230.

In 1985 the Company submitted a proposed conservation contracting pilot program to comply with the directives in D.P.U. 1720. In its analysis the Department found that the program proposal was not in compliance with the Order in D.P.U. 1720 because it failed to provide for the least-cost investment options. D.P.U. 1720-C, pp. 214, 221 (1985). The Company's

submission established a subsidiary to negotiate the best deal, below the Company's marginal cost, with conservation contractors for the installation of C&LM measures. Under the proposal the subsidiary would then charge BECo full marginal cost regardless of the price negotiated with the contractors. The proposal was designed to generate revenues through the subsidiary, but failed to place the subsidiary in competition with other conservation service vendors as directed in the Department's alternative C&LM option in D.P.U. 1720. The Department ordered the Company to file a revised conservation contracting pilot program, with a specific instruction that the program provide that contractor(s) be selected through a competitive bidding process as set forth in D.P.U. 1720. D.P.U. 1720-C, pp. 1-4.

On March 19, 1985, the Company requested a clarification of the Department's Order in D.P.U. 1720-C. First, the Company asked whether the specific nature of the finding of noncompliance in D.P.U. 1720-C meant that all other aspects of the proposed program had been approved. Second, the Company argued that the proposed program was acceptable as filed. The Department, in denying the Company's request, stated that the Company's proposal had already been found to be not in compliance with the requirements of D.P.U. 1720. Further, the Department stated that it was necessary for the Company to correct the proposal's deficiencies before the Department undertook a more detailed review of the proposed program. D.P.U. 1720-D, pp. 1-5.

The Company refiled on May 24, 1985. The Department is currently reviewing the Company's revised conservation contracting pilot program in D.P.U. 85-252.

2. Analysis of Company Actions

In the Company's last three general rate cases, the Department has sought to have C&LM considered as an integral part of the Company's generation expansion planning process. The Company was ordered in D.P.U. 906 to implement C&LM. In D.P.U. 1350 we established standards for C&LM and voiced our concern about the Company's oil and natural gas emphasis in C&LM. In D.P.U. 1720 we ordered the Company to implement C&LM consistent with our standards and to develop a pilot contractor C&LM program which provided BECo with greater flexibility in its demand planning process.

The Company contends that it continues to be confused and does not understand the Department's Orders on C&LM. On the one hand, the Company maintains that Department Orders have barred it from pursuing load management and conservation measures. On the other hand, the Company argues that, if it does undertake C&LM, the Department's standard for allowance of the C&LM expense in cost of service is not clear. From this, the Company concludes that pre-approval of C&LM program cost recovery is necessary.

The Company continues to misconstrue the Department's Orders on the issue despite repeated clarifications on the part of the Department. We have never barred the Company from conducting C&LM programs. To the contrary, we have required the Company to

engage in C&LM activity. In D.P.U. 906 (1982), we ordered the Company:

> ...to submit to the Department by July 1, 1982, a preliminary plan for a comprehensive program of conservation and load management. D.P.U. 906, p. 252.

In D.P.U. 1350 (1983), we stated:

> In reviewing utility-sponsored conservation and load management programs, the Department has consistently held that demand management strategies can serve the same purpose as supply options for meeting customers' present and future needs. In this case, we reiterate our view that a company's long-term planning process should give as much consideration to conservation and load management as to energy supply alternatives. D.P.U. 1350, p. 135.

In D.P.U. 1720 (1984), we again found it necessary to order the Company to implement specific C&LM programs by stating:

> ...in light of the Department's concern that the Company move forward from the research phase to the stage of implementing cost-effective C&LM programs, we find it necessary to direct BECo to implement a pilot program that is consistent with the philosophy and standards presented herein. D.P.U. 1720, p. 216.

In Fitchburg Gas and Electric Light Company, D.P.U. 84-145-A (1985), the Department stated:

> Consistent with Department precedent and the above analysis, the Department finds that Fitchburg, as an electric utility, has the obligation to integrate C&LM into its overall power supply planning process. This finding requires the Company to implement an electricity C&LM program within the context of a least-cost long-run supply planning strategy. D.P.U. 84-145-A, p. 171 (emphasis added).

The Department's longstanding policy of requiring companies to implement cost-effective C&LM programs is similarly stated in Fitchburg Gas and Electric Light Company, D.P.U. 1270/1414 (1983); Western Massachusetts Electric Company, D.P.U. 1300 (1983); Western Massachusetts Electric Company, D.P.U. 84-25 (1984); Cambridge Electric Light Company, D.P.U. 84-165-A (1985).

The Department's standard for the rate treatment to be accorded Company-run C&LM investments is equally clear. In D.P.U. 1350 the Department stated:

> As is the case for any cost of service expense, conservation and load management expenditures must be shown to be prudently incurred and must be known and measurable in order to be included in rates. D.P.U. 1350, p. 138.

In D.P.U. 1720 the Department discussed the appropriate ratemaking treatment for C&LM investments:

> The Department's fourth objective is to base cost recovery of C&LM investments on the value of the KWH saved. Basing cost recovery on the same standards that a utility should be using to evaluate its options shifts the risk associated with selecting cost-effective demand management strategies from the ratepayers to the utility decisionmakers. D.P.U. 1720, p. 204.

In *Western Massachusetts Electric Company*, D.P.U. 84-25 (1984), the Department stated:

> ...cost recovery for C&LM investments [must] be based on the value of the energy and/or capacity saved.... By limiting cost recovery to the value of savings, utility managers are more likely to implement decisions that are not only cost-effective in the short run but are also weighed against the risk that long-run benefits will not materialize. In short, utility managers will face the same risks as private sector decisionmakers and will act on behalf of stockholders and ratepayers in the most efficient manner. D.P.U. 84-25, pp. 216-217, 220.

It is not clear what else the Department could do to eliminate the Company's professed confusion about the need for and ratemaking treatment of Company-run C&LM programs. C&LM expenses are eligible for inclusion in the cost of service on the same basis as all other expenses: that they be prudently incurred and known and measurable. Investments in C&LM measures which are appropriately capitalizable are includable in rate base on the

same basis as all other Company investments in plant, that is, rate base treatment is allowed for investments which are prudently incurred and used and useful in meeting customer needs. Since C&LM options are to be considered on an equal basis with other supply options, it is only appropriate that the identical rate treatment be applied to both types of expenditures. This has been our consistently repeated message to the Company. Nevertheless, the Company continues to refuse to comply with the Department's C&LM directives because of what it calls continued confusion over ratemaking principles and because of its insistence that it receive pre-approval of all programs by the Department. We find the Company's position on both counts to be disingenuous.

We cannot fathom the Company's underlying motivation in this regard. The Department's standards for cost-recovery are clearly established, and the Company's demand that pre-approval be given before it proceeds with C&LM programs ignores Department precedent. We have rejected pre-approval in numerous cases in the past and, each time, explained the standard for C&LM cost allowance. In Western Massachusetts Electric Company, D.P.U. 1300 (1983), we stated:

> The Department will not permit the prospective amount of $726,000 to be included in cost of service because this amount is speculative.... Future conservation programs must be tied to test year expenditures and presented with proper documentation and justification. The Department directs the Company to specify how test year funds were used, including how much was spent on each program and how much the personnel costs were in total and on each program. D.P.U. 1300, pp. 94-95.

In D.P.U. 1350 we maintained:

> As a general matter, we find that an award of prospective program costs is inappropriate because it results in the transfer of the risk associated with planning decisions completely to ratepayers. D.P.U. 1350, p. 139.

We have examined these Orders, and our review convinces us that our Orders, when read in whole and fairly, are clear. We must conclude that the Company has intentionally and willfully mischaracterized our Orders so as to relieve it of the obligation to proceed with cost-effective C&LM programs. We find no support for the Company's conclusion that we forbade the Company to engage in C&LM programs. We find no support for the Company's conclusion that the applicable ratemaking standard for C&LM expenses and investments is unclear. We find no support for the Company's conclusion that pre-approval is warranted for C&LM programs.

Instead of attempting to carry out its public service obligation consistent with a least-cost strategy, the Company has avoided implementation of C&LM programs for a prolonged period by constructing every possible obstacle. We find the Company's actions in this regard belie its continued assertion that it seeks to comply in a good-faith manner with Department directives. The Company evaluates C&LM programs using a "revenue reduction adjustment." As BHA argues, this adjustment converts the evaluation to a no-losers test. The adjustment simply assigns costs of unrealized sales resulting from C&LM activity to the cost of the C&LM programs themselves, which, in effect,

requires that the programs be revenue-neutral (Exh. BE-802, p. 3). The no-losers test ensures that rates for all customers remain unchanged by C&LM activities, i.e., that the programs be revenue-neutral. We can reach no other conclusion than that the Company's revenue reduction adjustment is, by all meaningful measures, indeed a no-losers test, the precise test we rejected in the Company's last rate case. D.P.U. 1720, p. 202.

The Company has no pilot conservation contracting program in place as a result of problems with the proposal's submission in D.P.U. 1720-C. In that case the Company submitted an initial filing which necessitated the Department's rejection of the filing outright. Further, the Company has refused to implement any Company-run C&LM programs. The only reason we can perceive for the Company's mischaracterization of our Orders is either to avoid engaging in C&LM activities or to obtain guaranteed cost recovery of its C&LM expenses. All of the Company's mischaracterizations go to support its argument for pre-approval despite the record of past Department Orders. The Company's action in another case before the Department indicates the same desire for pre-approval and guaranteed cost recovery. See, Boston Edison Company, D.P.U. 86-71, pp. 14-16 (1986). Indeed, the Company has freely admitted that it refuses to make cost-effective investments in C&LM without pre-approval (Tr. 5, pp. 597-598, 627-628, 633).

The result of this willful disregard for Department standards on C&LM is that the Company's cost of providing service is above

the lowest cost consistent with reliable service. Provision of least-cost service is the Company's service obligation. Therefore, we find that the Company has violated that service obligation.

3. Remedies

BHA has suggested that the Department address the Company's violation of its service obligation and inaction on conservation and load management by: (1) penalizing the Company by reducing its allowed rate of return on common equity by one percentage point, (2) requiring it to purchase all cost-effective C&LM, and (3) requiring it to purchase BHA's C&LM proposals (BHA Brief, p. 19).

We will address BHA's recommendation that the Department penalize the Company's allowed rate of return on common equity in the section of this Order dealing with return on equity.

BHA's recommendation that the Department order the Company to purchase all cost-effective C&LM presents one method of initiating cost-effective C&LM programming. Recent Department Orders have firmly directed the Company to integrate C&LM fully into its supply and demand planning process. The Company, however, has failed to comply with such policy direction and has responded, in a less than satisfactory manner. BHA's recommendation, however, fails to address the integral relationship between supply and demand options in planning the most cost-effective utility system. We therefore find that BHA's second recommendation would not send a proper signal to the

Company regarding supply and demand planning.

BHA's recommendation to require that the Company purchase BHA's C&LM proposals provides another method of initiating cost-effective C&LM investment strategies consistent with the Department's standards enunciated in D.P.U. 1350 and D.P.U. 1720. The Company's only response to the BHA proposals suggests that there is no evidence on the record to support the BHA's claim that its programs are cost-effective. This argument is based on the Company's contention that BHA's programs have not been evaluated against marginal generation, transmission, distribution and energy costs (Company Brief, pp. 240-241).

BHA's estimates of the programs' cost-effectiveness provided simple payback calculations which assumed an avoided cost per KWH at the tenant level. While this calculation cannot be viewed as an accurate proxy for marginal cost pricing, BHA's assumed value fell well below the Company's marginal costs provided in both D.P.U. 1720 and its conservation contracting pilot program filing, D.P.U. 85-252. This suggests that the proposals have a strong probability of being cost-effective. However, the Company has made no attempt to address this question on the record or through recalculation of the BHA data.

Based on the evidence available on the record, we find that the Company should immediately review the BHA C&LM proposals, by a method consistent with the findings contained herein and in D.P.U. 1720, to determine whether they are cost-effective. Further, the Company is ordered to submit its findings to the

Department within 60 days from the issuance of this Order. This submission must include specific recommendations to proceed with the programs or a fully documented explanation of the programs' rejection, based upon standards consistent with the Department's Orders. We note that this is necessary because of the Company's failure to pursue and develop C&LM programs actively within the confines of past Department Orders. While it is not the Department's policy to usurp the Company's management decisions in this or any other area, we find it necessary to compel BECo to engage in conservation-related activities because of its continued disregard for Department directives.

VI. CAPITAL STRUCTURE

The Company's proposed capitalization of $1,515,344,000 includes several post-test year adjustments: (1) a reduction of $2,375,000 in long-term debt to recognize redemptions of series Q bonds through sinking funds on December 15, 1985, and December 15, 1986; (2) a reduction of $1,875,000 in long-term debt to recognize redemptions of series R bonds through sinking funds on October 31, 1985, and October 31, 1986; (3) a reduction of $11,520,000 in long-term debt to recognize the maturation of secured notes on November 15, 1985; (4) an increase in common equity of $5,244,000 issued from July 1, 1985, through September 30, 1985, pursuant to the Company's Dividend Reinvestment Plan ("DRIP") and the Employee Stock Ownership Plan ("ESOP"); (5) an increase in common equity of $11,700,000 expected to be issued from October 1, 1985, through June 15, 1986, pursuant to the DRIP; and (6) an increase in common equity of $800,000 expected to be issued in 1986 through the ESOP.

The Company supplied updates reflecting all known and measurable changes to the capital structure on June 2, 1986 (Exh. BE-101, p. 3, Revised). In the update, the Company indicated that the actual issuances through the DRIP from August 1, 1985, through June 2, 1986, totaled $13,635,000 and that the actual issuances through the ESOP totaled $2,617,000 through June 2, 1986. In addition, in its updated Exhibit BE-101, page 3, the Company stated that the equity component must be increased by $117,252,000 to reflect a March 1986 issuance of

two million shares and the debt component decreased to reflect the early retirement of $50,000,000 in nuclear fuel and related financing obligations.

The Department permits companies to include known and measurable post-test year changes to a company's test year-end capital structure to reflect the capital structure most representative of capital costs which the Company can expect to incur during the period in which the approved rates will be effective. Boston Edison Company, D.P.U. 906, pp. 106-109 (1982). The adjustments proposed by the Company reflect known and measurable changes to the various components of the Company's capital structure and capital costs. We find those adjustments to be appropriate. The Company's total capitalization is $1,564,852,000, reflecting a net increase of $49,508,000 for the most recent known and measurable changes. The amount and cost of each component of the Company's capital structure are shown on Schedule 5 attached to this Order.

VII. COST OF EQUITY

A. Introduction

The Company has requested a return on common equity of 15.25 percent, the same return allowed by the Department in the Company's last rate case. In support of its requested return on common equity, the Company presented the testimony of Zvi Benderly, an economist and principal of Benrose Economic Consultants, Inc. Mr. Benderly concluded that BECo should be allowed a return in the range of 15 to 15.5 percent. The bases of Mr. Benderly's analysis included discounted cash flow ("DCF") analyses, risk premium analysis, and an allowance for issuance costs.

There are two issues which have been raised by the parties. The first is whether the return on equity requested by the Company is appropriate. The second is whether the Company's return on equity should be adjusted to reflect its poor performance in the area of conservation.

B. Description of Mr. Benderly's Estimation Methods

Mr. Benderly performed two DCF analyses and three risk premium analyses. The first DCF analysis was for the Company alone and the second was based upon eight comparison companies selected by Mr. Benderly. A DCF analysis estimates the return on equity required by investors to be the percentage yield on dividend payments (dividend payment divided by market price) and adding to that the growth in dividends which investors expect.

To calculate the DCF for the Company alone, Mr. Benderly divided the current dividend by the average stock price over a range of months ending October 1985. He used a range of dividend yields between 8.98 percent (the ten month average ending October 1985) and 9.16 percent (the twelve month average ending October 1985). To determine the growth rate, he asserted that investors expect above average growth over the next five years and average growth thereafter. He stated that an above-average growth rate of 6 percent is reasonable, and that an average growth rate of 5 to 5.25 percent thereafter is reasonable (Exh. BE-500, p. 22). The use of these numbers results in a growth rate of 5.29 to 5.46 percent which, Mr. Benderly states, is less than the growth in retained earnings experienced by the Company since 1984. This results in a "barebones" cost of equity calculation, using the midpoints, of 14.45 percent (9.07 + 5.38) (id., p. 26).

Mr. Benderly's DCF analysis of comparison companies first required him to select comparison companies. He used ten selection criteria to determine whether companies were comparable. As a result of applying the ten criteria to 234 electric utilities, Mr. Benderly obtained a group of eight companies which he considers to be comparable. Mr. Benderly then calculated the DCF for each of these companies. He calculated the dividend yield for each company over the same ten and twelve month periods he used for BECo. The stock price used was the average of the monthly high and low price for the stock

and the dividend was the indicated dividend for the month. The resulting dividend yield range was 8.11 to 8.19 percent with the midpoint being 8.15 percent (id., pp. 36-37).

As with BECo, Mr. Benderly, after reviewing the historical growth in retained earnings, earnings per share, and dividends per share, assumed that investors would expect above average growth for the next five years and average growth thereafter. He stated that 6.5 percent was a reasonable number for above average growth and 5.25 percent for average growth for these comparison companies. This produced a composite growth rate of 5.59 percent. To complete his calculation, he took the midpoint of the dividend yield, 8.15 percent, and multiplied it by one-half of the near term growth rate of 6.5 percent to obtain an "approximation of the appropriate level of the expected dividend yield to be used in DCF analysis" (id., p. 37) to obtain an expected dividend yield of 8.41 percent. When the 5.59 percent growth rate is added to the 8.41 percent dividend yield, the result is a "barebones" cost of equity for the comparison companies of 14.00 percent (id., p. 43).

To determine whether the difference in barebones cost of equity capital between BECo and the comparison companies is warranted, Mr. Benderly conducted a relative risk analysis of the comparison companies and BECo. He reviewed sixteen financial and operating attributes of the comparison companies and BECo which he believed to be indicative of relative risk. In his opinion, BECo was riskier than the comparison companies

in eight of the factors, less risky in one factor, and seven factors showed no difference in risk. He concluded that the difference in risk between the comparison companies and BECo is such that it supports the difference in the barebones cost of equity calculated in the DCF analyses (id., pp. 44-55).

Mr. Benderly also conducted three risk premium analyses. A risk premium analysis attempts to measure the difference between the cost of corporate equity and some other less risky investment, e.g., corporate bonds or government securities. The first risk premium Mr. Benderly calculated used the risk premium on common stocks as compared to corporate bonds calculated by Ibbotson. Since electric utilities are, in general, less risky than most common stocks, Mr. Benderly reduced this estimated risk premium by BECo's beta coefficient as calculated by Value Line. The beta coefficent represents the risk of the particular company as compared to the average company. The resulting risk premium was then applied to the average yield to maturity of a representative group of BECo's bonds.

The risk premium calculated by Ibbotson for return on common equity as compared to corporate bonds over the period 1926 to 1983 is 5.2 percent. The Company's beta coefficient as estimated by Value Line is .55. Thus, the risk premium which Mr. Benderly applied is 2.9 percent (5.2 x .55). The yield on the bonds which Mr. Benderly used, calculated over the twelve months ending October 1985, is 12.35 percent. Thus, the return on equity calculated in this manner is 15.25 percent (12.35 + 2.9) (id., p. 64).

The second risk premium analysis presented by Mr. Benderly is based on the difference in the return on equity and the corporate bonds of the comparison companies. He calculated the yield on bonds for the comparison companies over the twelve months ending October 1985 as 12.18 percent. When subtracted from the calculated return on equity from the DCF analysis of 14 percent, the resulting risk premium is 1.82 percent. When this risk premium is added to BECo's bond yield of 12.35 percent, the resulting required return on equity is 14.17 percent. Mr. Benderly cautioned, however, that this number is not representative since he has already found that BECo is riskier than the comparison companies (id., p. 65).

Mr. Benderly's third and final risk premium analysis is based on the difference between the return on equity and the yield on corporate bonds for all companies which have the same bond rating as BECo by Moody's and Standard & Poor's. Seven companies met this criterion. The average bond yield calculated for the seven companies by Mr. Benderly for the twelve months ending October 1985 was 12.29 percent. The return on equity for each of the companies was the calculation of total return done by Salomon Brothers, which averaged 14.73 percent for the seven companies. This resulted in a risk premium of 2.44 percentage points. When added to the bond yield calculated earlier by Mr. Benderly for BECo of 12.35 percent, the indicated return on equity is 14.79 percent (id., pp. 66-67).

Mr. Benderly stated that, excluding the risk premium calculation of the comparison companies which he believed to be

unrepresentative, the average barebones cost of equity for BECo, using the remaining three calculations (DCF and the other two risk premiums) was 14.83 percent. He concluded from this analysis that the barebones cost of equity for BECo thus lay in the range of 14.7 to 14.8 percent (id., p. 68). He maintained, however, that the costs of issuance should be added to the barebones cost of equity in order that, after issuance, the barebones cost of equity is determined. His calculation of issuance cost for BECo was 33 basis points, which raised the cost of equity range to 15.03 - 15.13 (id., p. 71). He also states that if a ten percent adjustment for dilution[19/] is allowed, the cost of equity for the Company is in the range of 15.7 to 15.8 percent (id., p. 73).

As a final input to his recommendation, Mr. Benderly evaluated the price-book ratios of electric utilities and non-regulated firms. He stated that the price-book ratios of non-regulated industrial firms over the period 1955 to 1985 was between 1.5 and 2.0. He asserted that while electric utilities maintained similar ratios in the 1950's and 1960's, they fell sharply in the 1970's and 1980's. He concluded from this that since "the price-book ratios of utilities, and of Boston Edison, are below the price-book ratios of industrials ... utility rates

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19/ Dilution, according to Mr. Benderly, occurs when a utility's price/book ratio is below 1.0. In this case, according to Mr. Benderly, additional issuances of stock dilute the existing shareholders ownership share in the Company (Exh. BE-600, pp. 77-78).

of return, and that of Boston Edison, are insufficient under the comparable earnings test" (id., p. 76). Based on this analysis and the measures of cost of equity he conducted, Mr. Benderly concluded that the minimum range of the cost of equity for the Company is 15.0 to 15.5 percent.

C. Parties' Positions

The Attorney General maintains that the cost of equity requested by BECo is excessive. First, he notes that the yield on corporate bonds with the same rating as BECo's has decreased 400 basis points since the Company's last rate case, yet the Company makes no recognition of this fact and requests the same return on equity granted in that case (Attorney General Brief, p. 104).

Second, he argues that the DCF for BECo conducted by Mr. Benderly is incorrect. He maintains that Mr. Benderly did not match dividends with stock prices, because he used the higher recent dividend rate rather than the rate in effect in each month. He also alleges that Mr. Benderly's growth rate calculation is too high. A better estimate, he states, is the expected growth in retained earnings obtained by multiplying the most recent earned returns on common equity by the retention ratio (the opposite of the payout ratio). Using this calculation, he argues that the highest growth rate which can be expected is 4.35 percent, based on the 1985 return on common equity of 14.5 percent times the Value Line projected retention ratio of 30 percent (Attorney General Brief, pp. 107-113).

Third, he argues that Mr. Benderly's DCF analysis for the comparison companies is flawed. Given the rise in stock prices, he states, a six month average ending December 1985 provides more representative results than a twelve month average. Additionally, he argues that the growth rate used by Mr. Benderly in this analysis is too high (Attorney General Brief, pp. 115-117).

Fourth, he argues that the risk premium analyses are incorrect. He maintains that the bond yield calculated for BECo is too high because it uses some data based on Moody's reports. He argues that the Moody's calculations are too high because the methodolgy used to select the input numbers uses stale data. Additionally, he states, that the use of the Ibbotson risk premium must be rejected because it calculates only earned risk premium, not expected, and because some double-counting of risk premiums might occur. The comparison companies risk premium is unusable, according to the Attorney General, because it is based on the equity return calculated using the DCF which is incorrect. Finally, he alleges that the risk premium based on the seven companies with the same bond ratings as BECo is incorrect since the return on equity calculation in these measures is inappropriately based on spot estimates and calculated differently from the DCF which has been accepted by the Department (Attorney General Brief, pp. 119-125).

Fifth, the Attorney General argues that the adjustment for issuance costs by Mr. Benderly must be rejected. It is contrary to Department precedent, he states, and Mr. Benderly has given

no reasons why the Department should change its precedent on this matter.

Based on his own analysis, which uses a dividend yield of 8.71 percent, calculated as the average yield over the twelve months ending December 1985 times one half the growth rate, plus the growth rate which is calculated by him to be 4.35 percent (see above), he recommends a maximum return on equity of 13.06 percent (Attorney General Brief, pp. 114, 128).

The Company argues that the cost of equity requested by it is supported by the analysis and testimony of Mr. Benderly and is reasonable. The DCF performed by Mr. Benderly for BECo is correct, the Company claims. It states that Mr. Benderly's method of calculating the yield is acceptable (Company Brief, pp. 25-26). It also argues that the Attorney General's recommendation that the historical growth in retained earnings be used as the growth rate in the DCF calculation is wrong. The Company argues that the Department has already rejected a growth rate in retained earnings calculated over a period different than the period for the dividend yield and that growth in retained earnings was, for two of the last five years, unrepresentative because of the extraordinary loss the Company had with regard to Pilgrim 2 (<u>id</u>., pp. 28-31).

The Company also claims that the Attorney General's criticism of the growth analysis for the DCF for the comparison companies is incorrect. It maintains that the Attorney General bases his criticism of Mr. Benderly's analysis on only a portion

of the possible proxies for growth rate that investors might examine, and so his analysis of Mr. Benderly's work is incomplete (Company Brief, p. 32).

The Company also rejects the Attorney General's contentions regarding Mr. Benderly's risk premium analysis. The Company argues that Moody's calculated yields are just as reliable as Standard and Poor's. It maintains that the Attorney General's arguments regarding the double-counting of risk premiums are based on a case whose facts are not applicable to this case. Finally, it claims that the Attorney General's criticisms of the risk premium based on the Salomon Brothers data is wrong. It states that since Mr. Benderly averaged the monthly Salomon estimates, no spot yield was used, and that the calculation used by Salomon Brothers is in essence a DCF calculation (Company Brief, pp. 32-36).

Finally, the Company argues that Mr. Benderly did not make an adjustment for issuance costs, but just noted what those costs would be to emphasize the conservative nature of his recommendation (Company Brief, p. 37).

D. Analysis and Findings

The DCF for BECo performed by Mr. Benderly relies on two separate calculations: a dividend yield and a growth rate. The Attorney General maintains that it is the monthly dividend yields which should be averaged to determine the dividend yield while the Company maintains that the latest dividend yield divided by the average price is the appropriate measure. The only time in which these calculations would yield a different

result is when the dividend has changed during the time period under study, as is the case here. If the dividend has increased in the time period and the latest, higher dividend is divided by the average price over the period, the result is higher than the average of the monthly dividends over the same period (which use the previous lower dividend while it was in effect). Because investors presumedly do not know of a dividend increase appreciably before it is voted, a calculation which uses the higher, later dividend and average stock prices mismatches prices and dividends. Therefore, we find the Attorney General correct in this part of his contention.

The Attorney General also argues that the growth rate used by Mr. Benderly in his analysis is too high. The Company responds that the suggestion of the Attorney General to use a historical average is inconsistent with Department precedent and unrepresentative. Mr. Benderly examined the historical growth rates of several indicators which investors might examine to determine the expected growth rate of the Company. He then applied his judgment to determine the growth rate which investors might expect.

As both parties correctly note, the Department has, in the past, examined four measures of growth with regard to the DCF method: growth in dividends per share, earnings per share, book value per share, and the growth in retained earnings. The Attorney General argues that the Department has correctly determined that growth in retained earnings is the most appropriate measure of these four for estimating the DCF growth

rate and would have us use a three or five year historical average. The Company states that Mr. Benderly did examine growth in retained earnings over a historical period. But he rejected the use of a long historical period because earnings in 1982 and 1983 were depressed because of the effects of the cancellation of the Pilgrim plant and because he believed the Department's preference is to have the period over which the growth rate is calculated match the period over which the dividend yield is calculated.

Mr. Benderly, however, did not stop with the examination of the historical period; he reviewed growth projections for BECo from various sources and concluded that an above-average growth was expected by investors over the next five years, declining to average growth thereafter.

There is no known and measurable basis which underlies Mr. Benderley's projections. The Department has no information as to how the projections Mr. Benderly refers to were conducted. In short, we must reject Mr. Benderly's above average growth for the future as totally unsubstantiated.

What remains, then, is the recent growth rates for retained earnings. In considering these growth rates, as well as the dividend yield, it must be noted that the values provided are nominal values, i.e., they reflect the level of inflation at the time. Real values are corrected for inflation and would represent, along with today's inflation rate, a more accurate estimation of the dividend yield and growth rate. There are two

ways to account for the reduction in inflation and its concomitant effect on the dividend yield and growth rate. The nominal numbers may be adjusted by a measure of inflation or, because a shorter, more recent period more accurately reflects today's inflation rate, the dividend yield and growth rate can be calculated over that shorter period. See Table 3.

With regard to the comparison company analysis conducted by Mr. Benderly, the Attorney General argues that a six month period over which to calculate the dividend yield would be more representative and that the growth rate was too high. In turn, the Company argues that Mr. Benderly's growth rate is not too high and considers all relevant factors. We need not reach a conclusion on this issue because we are unable to find that the companies selected by Mr. Benderly are, in fact, comparable.

Mr. Benderly used ten selection criteria in choosing his comparison companies. He conducted no statistical analysis to determine whether the criteria are in fact significant in determining the return on equity for electric utilities. This situation is much akin to the situation confronted by the Department in regard to setting performance goals for electric utilities. There, utilities maintained that a myraid of factors made their plants uncomparable with the plants of other utilities. At the Department's direction, the utilities performed statistical analyses to determine which factors actually resulted in a population of plants which was statistically different from the population as a whole. The

TABLE 3

MONTH/YEAR	EXH. AG-2 NOMINAL MONTHLY DIVIDEND YIELD	EXH. AG-3 NOMINAL AVERAGE STOCK PRICE	TR. 38-39 NOMINAL MONTHLY DIVIDEND ANNUALIZED	NOMINAL MONTHLY YIELD (D / C)	INFLATION RATE*	REAL MONTHLY YIELD (E/(1+F))	UPDATE SCHED. 2 FORECAST INFLATION RATE*
1/85	9.440%	$34.31	$3.24	9.443%	2.952%	9.173%	2.459%
2/85	9.160%	$35.38	$3.24	9.158%	2.952%	8.895%	2.459%
3/85	8.700%	$37.25	$3.24	8.698%	2.952%	8.449%	2.459%
4/85	8.420%	$38.50	$3.24	8.416%	3.301%	8.147%	2.459%
5/85	8.230%	$39.38	$3.24	8.228%	3.301%	7.965%	2.459%
6/85	7.740%	$41.88	$3.24	7.736%	3.301%	7.489%	2.459%
7/85	8.090%	$40.06	$3.24	8.088%	2.906%	7.859%	2.459%
8/85	8.390%	$38.62	$3.24	8.389%	2.906%	8.153%	2.459%
9/85	8.750%	$39.31	$3.44	8.751%	2.906%	8.504%	2.459%
10/85	8.990%	$38.25	$3.44	8.993%	3.250%	8.710%	2.459%
11/85	8.430%	$40.81	$3.44	8.429%	3.250%	8.164%	2.459%
12/85	7.870%	$43.69	$3.44	7.874%	3.250%	7.626%	2.459%
1/86		$44.81	$3.44	7.677%	2.501%	7.490%	2.459%
2/86		$48.62	$3.44	7.075%	2.501%	6.903%	2.459%
3/86		$51.38	$3.44	6.695%	2.501%	6.532%	2.459%
4/86		$50.31	$3.44	6.838%	1.771%	6.719%	2.459%
MOST RECENT 12 MO. AVG.	8.518%	$43.09		7.898%	2.862%	7.676%	2.459%
MOST RECENT 6 MO. AVG.	8.420%	$46.60		7.431%	2.629%	7.239%	2.459%
MOST RECENT 3 MO. AVG.	8.430%	$50.10		6.869%	2.258%	6.718%	2.459%

GROWTH FROM RETAINED EARNINGS 12 MONTHS ENDING MARCH 86 EXH. AG-3. SCHED. 2. P. 1	4.880%	2.862%	4.744%		
REQUIRED RETURN ON EQUITY DIVIDEND YIELD + GROWTH RATE					
RETURN USING 12 MONTH DIVIDEND YIELD	12.778%		12.420%	2.459%	12.726
RETURN USING 6 MONTH DIVIDEND YIELD	12.311%		11.983%	2.459%	12.278
RETURN USING 3 MONTH DIVIDEND YIELD	11.749%		11.462%	2.459%	11.744

* INFLATION RATES CALCULATED AS THE PERCENTAGE CHANGE IN THE GNPIPD FROM ONE QUARTER TO THE NEXT. COMPOUNDED TO YIELD AN ANNUALIZED INFLATION RATE.

results of this exercise were that few factors determined plants whose performance, as a population, was different from the population as a whole (e.g., Boston Edison Company, D.P.U. 84-274 (1985); Cambridge Electric Light Company, D.P.U. 85-234 (1985)).

Here we do not find Mr. Benderly's comparison companies incorrect, but are unable to find them meaningful or correct since he has presented no statistical analysis. Because the burden of proof is on the Company to show that the factors used to select the comparison companies are indeed significant in explaining the comparability of companies and the differences in returns on equity, and because it has not made that showing, we must find that the results of the comparable company analysis cannot be used. We note, additionally, that similar reasoning applies to the selection of the criteria used in the analysis of risk between the so-called comparable companies and BECo conducted by Mr. Benderly.

The Attorney General criticizes the risk premium analyses of Mr. Benderly on many grounds. Our analysis of the risk premiums calculated by Mr. Benderley reaches similar conclusions. We need not discuss the Attorney General's arguments regarding the inclusion of Moody's bond yields in calculating the risk premium for the Company except to note that the use of federal government securities, which are traded every day and always have a market price would alleviate much of the contention between the parties in this case.

The Ibbotson risk premium analysis put forth by Mr. Benderly is inappropriate and must be rejected. The period over which Ibbotson calculates this risk premium includes: the stock market crash, the Great Depression, World War II, the unprecedented capital expansion of the 1960's, and the inflationary period of the 1970's. Moreover, Mr. Benderly admits that during this time some of the risk premium calculations are negative, hardly a reasonable expectation for today. We would not have an aversion to a risk premium analysis which could show that the risk premium was calculated over a historical period determined to be reasonably representative of the future or was the result of objective statistical analysis which took unusual occurances into account. But the use of unadjusted data taken from the period used by Mr. Benderly can be given no credence whatsoever.

The risk premium calculated based on the comparison companies, as discussed above, is of no use here because we are unable to find that the criteria used to select the companies are, indeed, significant. This leaves the final risk premium, companies with the same bond rating as BECo. As with the comparison companies, there has been no showing that the risk premium between A rated companies is different than that of AA or AAA or BB companies. Therefore, we cannot find that the criterion of bond ratings is a significant determinant of comparability and must reject the conclusion drawn from the analysis.

The final issue raised by the Attorney General is the adjustment for issuance costs. The Company asserts that the Attorney General, in his arguments on this issue, is referring to the effects of dilution resulting from market pressure, which it claims were not included in Mr. Benderly's calculation. There are, in fact, two types of costs which Mr. Benderly refers to as issuance costs and which he maintains cause dilution. The first is the cost of the issuance itself which includes underwriter compensation and company expenses (Exh. BE-600, pp. 69-70 refer to these costs as flotation costs; p. 71 refers to them as issuance costs). The second is to account for what Mr. Benderly claims is the need to avoid dilution (id., p. 71 "opportunity of avoiding dilution"; p. 73 as issuance costs). He does include the first in his estimate and not the second.

As the Attorney General argues, the Department has not allowed either type of issuance cost in the calculation of a determination of the reasonable range of common equity returns. Our reasoning, is that investors are knowledgeable and factor in the issuance costs a company incurs when they determine their required return. Mr. Benderly has provided no analysis which shows our reasoning to be incorrect, and so we find that no adjustment should be allowed for issuance costs of any sort.

The standards by which allowed returns on equity have been judged are Hope and Bluefield. In Hope the United States Supreme Court stated:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of

> the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944), p. 603.

In Bluefield the Supreme Court stated:

> The return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. Bluefield Water Works and Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679 (1923), p. 693.

Using the information in Exhibit AG-2 (update), as well as the information in Exhibit BE-101, p. 28 (update) for inflation rates, a range of returns on equity for BECo can be calculated. Table 3 contains such an analysis of the Company's cost of equity using a DCF analysis for the Company itself over a range of possible time periods. Column E on this table calculates the average nominal dividend yield of the Company over recent historical periods. Column G calculates the real yield (i.e., the yield net of inflation) over the same periods. The nominal growth rate in retained earnings over the recent 12 month period from AG-3 is shown as well as the real growth rate over the same period. At the bottom of the table the nominal dividend yields are matched with the nominal growth rate to calculate the return on equity required by investors. Also, the real dividend yields and growth rates are matched in a similar manner and then adjusted for inflation to yield nominal returns on equity. This analysis yields a reasonable range for allowed return on equity between 11.74 and 12.79 percent. While aspects of this method are flawed, we find that in this case the results produced by

using updated data provide a reasonable range of rates of return which can be used in the determination of the Company's cost of equity. Indeed, had Mr. Benderly's other methods not been found so deficient, the Department could have used updates based on them to aid in its determination of a reasonable range. Given the reduction in interest rates and in inflation which has occurred since the test year and since the 12 months used by Mr. Benderly, we find that the range produced by this method is reasonable for use in this case. The question which remains is where, within this reasonable range, the return for the Company should lie.

The BHA argues that the Company has violated its franchise obligation. It states that the Company has the responsibility to provide least-cost electric service consistent with the reliability of service, and that this responsibility requires that the Company integrate conservation and load management programs into its supply planning. According to the BHA, the Company has not met this requirement and has, indeed, stated in public speeches and sworn testimony that it will not pursue cost-effective conservation. As a result, the BHA states, BECo has imprudently increased its risk and thus its cost of equity and so a reduction in its allowed return on equity of 1 percentage point must be made (BHA Brief, pp. 12-18; BHA Reply Brief, pp. 2-7).

The Company responds that it has not acted imprudently in its C&LM and that it has pursued all cost-effective conservation measures. It also states that investors have not increased their perception of BECo's risk because of its conservation

policies and so its cost of equity has not been raised (Company Brief, pp. 23-24; Company Reply Brief, p. 35).

As we have found above, the Company has, indeed, failed to fulfill its service obligation to provide least cost power through its willful disregard of its responsibilities in the area of conservation. Further, as discussed in Section II above, the failure of the Company's management to manage has permeated the Company's entire capacity expansion planning process and could jeopardize the health and safety of its customers and the economy of the region. On these bases we must conclude that Boston Edison Company is neither efficiently nor economically managed.

For these reasons, we would find that the return on equity allowed the Company should be at the absolute bottom end of the reasonable range. To place the return on equity at that point, however, would disregard the exceptional performance in the one area which stands out from the dismal performance record of the Company's management overall. The Company has been a leader among utilities which come before the Department in the area of rate structure. Its responsiveness with regard to cost allocation and cost of service studies and its understanding of Department Orders with regard to rate design have enabled it, and the Department, to move toward cost-based rates with appropriate price signals while avoiding major pitfalls along the way. For this reason alone, we find that the return on

equity for the Company should be set approximately one quarter of a percentage point above the bottom of the reasonable range for the cost of equity. Therefore, the allowed return on equity for the Company shall be 12.00 percent.

VIII. RATE STRUCTURE GOALS

Rate structure is the level and pattern of prices that customers are charged for use of utility service. The rate structure each rate class faces is a function of the cost of serving that rate class and the design of the rates calculated to cover that cost.

The Department's goals for utility rate structures are efficiency, simplicity, continuity, fairness, and earnings stability. There are two steps in determining rate structures: cost allocation and rate design. The cost allocation step allocates a portion of the company's total costs to each rate class. The rate design step determines the pattern of prices in the rate structure for each rate class which produces the allocated revenues.

The cost allocation process requires two objectives to achieve the Department's goals. First, the allocation process should result in an overall level of rates for each rate class which reflects the costs a company incurs in serving that rate class. Second, the cost allocation process, if accurate, should be the basis of determining the costs each rate class should bear.

The cost allocation process comprises five tasks. The first task is functionalization, or the grouping of costs by function. In this task, costs are defined as being related to the production, transmission, or distribution function of providing service. The second task is classification. In this

task the expenses in each functional category are classified according to the forces underlying their incurrence. Thus, the expenses are classified as demand-, energy-, or customer-related. The third task is to determine what allocator is most appropriate for each classification within each function. The fourth task in the cost allocation process is to allocate all of a company's costs to each of the rate classes based upon the cost groupings and the allocators chosen, and to sum the allocations by rate class to determine the cost of serving each rate class. The fifth and final task is to examine the cost of serving the rate classes in comparison to the revenues they provided in the test period. If these amounts are close, the revenue increase or decrease may be allocated among the rate classes so as to equalize the rates of return and ensure that each class pays the cost of serving it. If the differences between the allocated costs and revenues produced are great, however, then for reasons of continuity the revenue increase or decrease may be allocated so as to reduce the differences in rates of return, but not equalize them in a single step.

There are also two rate design objectives which are necessary to achieve the Department's rate design goals. First, the rate design must be such that the rate structure for each given class produces revenues to cover the cost of serving that class. Second, the rate design should be based on marginal costs.

There are four tasks which comprise rate design consistent with these goals and objectives. First, a marginal cost study must be done which accurately determines a company's marginal costs. Second, marginal costs must be converted into rates for each rate class. Third, the marginal-cost-based rates are reconciled with the class revenue requirement by adjusting the most inelastic portion of the rate. Fourth, the resulting rate structure must be compared with existing rates. If it is found to represent a change which violates the goal of continuity, then the existing rates must be adjusted to move the rate design toward marginal-cost-based rates in a manner which does not violate the goal of continuity. See Boston Edison Company, D.P.U. 1720 (1984); Western Massachusetts Electric Company, D.P.U. 84-25 (1984); Fitchburg Gas and Electric Light Company, D.P.U. 84-145-A (1985); Cambridge Electric Light Company, D.P.U. 84-165-A (1985); Massachusetts Electric Company, D.P.U. 85-146 (1986).

IX. COST ALLOCATION

A. Description

The Company performed an embedded cost of service study ("COSS") for the purpose of allocating its costs and assigning responsibility for the recovery of the Company's total revenue requirement among the Company's rate classes. In accordance with the Department's Order in D.P.U. 1720, the Company developed a time-differentiated embedded COSS. Time differentiation involves determining costs that are directly attributable to specific hours of the day or periods in the test year. The COSS allocates system costs to specific hours or periods in the test year. The allocated costs are assigned to the rate classes that are using the system at the time the costs are incurred. This correlates costs of providing service with rate classes and time periods.

The cost allocation process involves essentially five steps, described in D.P.U. 1720. These steps are: functionalization, classification, determination of allocators, allocation of costs based on selected allocators, and allocation of the revenue requirement among rate classes.

The functionalization process categorizes plant and expenses as production, power supply transmission, local transmission, high-tension distribution, and secondary distribution. The Company then classified the functionalized costs as demand-related, energy-related, or customer-related based upon the reason for the costs' incurrence (Exh. BE-200, pp. 2-3).

The Company determined which costs in each functional category are attributable to each costing period. Costing periods are the smallest units of time in which costs are determined. In this case, the costing periods are hours in three representative days (peak, typical weekday, typical weekend day) in each month (Exh. BE-200, pp. 16-17). The Company allocated the demand-related and energy-related costs in each hour to the rate classes based on their share of energy or demand within each time period. Customer-related costs were allocated based on the number of customers (or weighted customers) in each class. Finally, the allocated costs were summed across all periods, classifications and functions by rate class to form the total revenue requirement for each class. The Company then compared computed costs to the total revenues the class generated to determine whether the class was providing revenues sufficient to cover the costs of serving it (Exh. BE-200, p. 3).

B. Load Data

The five-step process described above presumes the availability of accurate and reliable load data. This is obtained as a result of load research. Load research is the study of company loads by rate class and for the system as a whole. It enables a company to determine its system peak, the peak of the individual classes, and the load profile for each class and for the entire system. The information about system and class loads is necessary to the COSS because, whatever

allocator is chosen, the load data are necessary to calculate the allocation factors which are used to allocate costs.

The Company collected load research data from its own load research program. For the rate classes, the Company used data collected from the test year, except for some small rate classes and the streetlighting, class where data were collected for a period other than the full test year (Exh. BE-203). Load research meters collected load data for all classes, except streetlighting, which, since its period is determined by hours of darkness, has a load that can be calculated. The Company used samples for each class of sufficient size to offer a 95 percent confidence level with ± 5 percent accuracy for its largest rate classes and a 90 percent confidence level with ± 10 percent accuracy for the smaller classes. The final load shapes were prorated to match billing KWH and then brought up to the generation level using loss factors by month (Exh. BE-200, pp. 16-17).

Robinson argues that the Company's load research is not complete for all rate classes, particularly for the residential water heating class (Robinson Brief, p. 3), and that the Company does not have any actual load data for the residential water heating class allocation. Robinson also states that for some other small residential classes the data are outdated and are not taken from months that they are intended to represent (Robinson Brief, p. 3).

The Company maintains that its load data are both accurate and reliable. The Company argues that the out-of-period data

are limited to a small segment of the residential class (Company Brief, pp. 291-293). The Company states that, although it collected data for small residential classes during only one-half of the test year, the data were adjusted to obtain a sufficient level of accuracy.

The Department, in previous Orders, has directed the Company to improve its load research program, and we find that the Company has responded appropriately.

The issues raised by Robinson are not supported by the evidence presented. The Company, in response to the Department's Order in D.P.U. 1720, installed load meters for the classes in question in a timely manner and collected data for six months within the test year (Company Brief, pp. 291-293). The Company then properly adjusted the data to reflect loads for the full test year. In these circumstances, we find that the data for these classes, which are but a small percentage of the total residential customer base, are sufficiently reliable and adequate.

Accordingly, we find that the Company has collected sufficient load research data and has made acceptable adjustments for the purposes of this case.

C. Allocators

1. Description of the Allocation Process

BECo's COSS used test year per-book values with separate schedules identifying and allocating its proposed adjustments. The functional categories used by the Company were: production,

transmission ("PST") (voltage levels greater than or equal to 115 kilovolts ("KV")), high-tension distribution ("PSD") (voltage levels less than 115 KV), and secondary distribution (costs related to the local distribution system) (Exh. BE-200, pp. 2-3).

The Company then took costs within each functional category and classified them according to cost causation. The classification categories were demand (capacity), energy (continuous power requirements), or customer (customer and billing) (Company Brief, p. 243).

The Company used a variety of allocators in its COSS. Demand-related production costs were allocated using a probability of dispatch method ("POD"), which the Company was ordered to file in this case. The Department ordered the Company to file the POD allocator because the Department has found previously that the POD method of allocating demand-related PSP costs is preferable to other methods. See D.P.U. 1580, pp. 118-121; D.P.U. 1720, pp. 125-128.

The POD model assigns costs from each generating unit to the hours that the plant is likely to run. Total costs in each hour are then allocated to the classes in each hour based upon each class' load in that hour. The POD model allocates test year operating expenses to specific hours through a simulated dispatch model which determines the probability of a unit operating in any hour during the test year.

The POD model requires the following input: an operating specification for each unit which consists of running costs, scheduled maintenence, equivalent forced outage rate and capacity; and the loads which the units are dispatched to meet. The Company normalized these inputs by removing abnormal occurrences and using the operating performance of each unit in the test year. The units were classified as: must-run, conventional, limited energy, storage, and external. The POD model dispatches the units to fill the load duration curve with the least-cost mix of generating units at each level of load. Once all the units were allocated across all hours, the cost in each hour was allocated to each rate class in proportion to each class' share of total demand in each hour (Exh. BE-200, p. 5).

Energy-related production was allocated by weighted MWh at the generation level. This is similiar to the method used in D.P.U. 1720 and 1350. This allocation factor was developed directly from the POD model, which computed cost summaries by period. BECo determined the average running costs for each of the 864 costing periods were determined by the POD model, and calculated the energy allocation factor by multiplying each class' MWH in a period by the average running cost in that period. By summing these values for each class and dividing by the average annual running cost, the Company obtained a weighted MWH use by class. This weighted MWH use by class provides for greater accuracy since average and marginal fuel costs are different in each period. When divided by the total weighted

MWH, it provides a precise estimate of the class' share of production energy costs (Exh. BE-200, p. 7).

BECo segregated, by voltage level, transmission and distribution ("T&D") plant investment into transmission, high-tension and secondary. The costs in each of these groups were then allocated to time periods following an approach similiar to the POD method. The T&D allocation is based on a coincidence probability with peak, not on outage probability, as in production.

T&D plant, at each voltage level from lowest to highest, by geographic region, is designed to meet the peak demand placed on it by customers. The peak demand on any portion of the T&D system is a function of the peak loads on the lower-voltage-level segments to which it is connected and of the coincidence of those peak loads with the peak load on the higher-voltage-level segments. Coincidence, in this case, is the ratio of a lower-voltage-level segment's load at the time of the higher-voltage-level segment's peak to the highest peak load on the higher-voltage-level segment.

For example, a residential distribution line may have a maximum load of 100 KW. At the time of the peak load on the substation to which it is connected, it may have a load of 60 KW. This segment's coincidence would then be 60 percent. Similarly, the coincidence factor of the substation could be developed as compared to the transmission substation which serves it. All the distribution and transmission loads can be

compared in this manner to determine coincidence factors. But because the T&D system is so complex, the Company is unable to determine the aggregate coincidence factor for a rate class. If it could, it could use the coincidence factor and the installed cost of the T&D equipment which serves the class to allocate costs.

The Company, however, does have measurements of the distribution and transmission system aggregate hourly loads. It also has class demands by hour. It thus assigned transmission, high-tension, and secondary costs to each hour based on that hour's probability of being the coincident peak for each of those voltage levels, respectively. Transmission, high-tension, and secondary costs in each hour were then allocated to each rate class based on its demand at each voltage level in that hour.

BECo allocated customer plant and associated expenses directly to customers on the basis of the number of customers or customer meters weighted by the relative costs of a particular installation. For example, "weighted customer meters" is an allocator that allocates costs of meters on the basis of the total cost of the meters serving customers in each class. This reflects the fact that large users require larger, more expensive meters.

2. Parties' Positions

The Company states that the POD allocator is an accurate method for the allocation of production costs. The Company

argues that the POD method is a dynamic method, less peak-intensive than most static allocation methods, such as peak and average ("P&A"). The Company also argues that the POD method captures the true nature of a peak load which persists for many hours as well as the nature of base loads which must be served almost continuously (Company Brief, p. 245). The Company maintains that the POD method is sensitive to the type of production inventory and the basic shape of the Company's load curve. According to the Company, the POD method emphasizes the importance of both the magnitude and duration of load on the system (Company Brief, pp. 245-246). The Company also argues that the POD method accounts for the operation and performance of individual generating units within the relative maintenance schedules of units on the system, and for the loss of load probability in each hour (Company Brief, pp. 248-249).

The Consortium argues that the POD allocator is essentially an energy allocator, and it therefore fails to reflect adequately the impact of peak demand on costs (Consortium Brief, pp. 9-10). The Consortium suggests that, instead of using the POD method and apportioning capacity responsibility equally across all hours, the POD method should be used in combination with the capacity factor method. The Consortium states that the capacity factor ("CF") method assigns costs to a unit only across the hours it was intended to run to make the unit economical, instead of across all hours that it has a probability of running (Consortium Brief, pp. 12-13).

The City argues that the POD method results in an allocator that approximates a straight, unweighted energy allocation. It submits that energy as the basis for cost causation should not be the sole factor for allocating power supply costs (City Brief, pp. 12-13). The City further argues that the POD method produces allocation results that are counterintuitive (City Brief, pp. 13-14). The City maintains that the P&A method is a better allocator because it better recognizes the capital costs associated with the streetlighting classes (City Brief, pp. 5-6).

3. Analysis and Findings

In order to determine whether the POD allocator is an appropriate allocator for production capital costs, we must determine the reasons behind the incurrence of those costs. This in turn requires a review of the nature of the capital costs of generating units.

There are basically three types of generating units that a utility constructs: base-load, intermediate, and peaking. Base-load units have the highest capital cost (both in total and per KW) and the lowest variable cost (per KWH; peaking units the lowest capital cost and highest variable cost; and intermediate units fall in between. Base-load units are economical only if they will run a large number of hours each year, because it is only with a large number of running hours that their high capital cost is offset by the low variable cost as compared to intermediate and peaking units. In contrast, if the company

load profile is such that additional capacity is needed for only a few hours in the year, a peaking unit is the least expensive choice, on a total-cost basis, because even though it has high variable costs, its capital costs are very low.

Given the tradeoff between capital cost and variable cost, it is clear that almost all of the capital cost of a peaking unit is capacity-related. In turn, since base-load units have a capital cost that is at least three times that of peaking unit, the majority of the capital cost of a base-load unit is energy-related. This is because if the utility only needed capacity, it would build a peaking unit. When it builds a base-load unit, it merely takes the opportunity, since the capacity is needed over a significant number of hours, to lower its total cost by lowering the energy cost. Thus, the allocator used for generation plant, if it is to allocate these costs based upon the reasons behind their incurrence, must recognize that capital costs have both a capacity and an energy component, and that the proportions are not constant between the types of generating plants.

The P&A allocator attempts to recognize this difference by creating an explicit division of capital costs: those which are energy-related and those which are capacity-related. It uses the system load factor to determine the proportion of capital costs which are energy-related. Typically, this is about 60 percent. This portion of costs is then allocated on the basis of energy used by each class. The remaining portion of costs,

usually about 40 percent, is then assumed to be capacity-related. This portion of the costs is allocated to the rate classes based upon some measure of the classes' responsibility for the company's peak demand.

The 60/40 split between energy- and capacity-related costs used by the P&A method is applied to all types of units. Thus, base-load units are assigned a 60/40 split between energy and capacity even though the energy portion of their capital costs is far higher. Peaking units are assigned the 60/40 split as well, even though their capital costs are, for all practical purposes, completely capacity-related. The only way that the P&A method can result in a split between energy- and capacity-related capital costs which is appropriate, then, is if the proportions of different types of plant are such that the overall portion of capital costs related to energy is in fact 60 percent. This is seldom the case.

The POD method takes a different tack. It does not explicitly divide the costs of each plant into capacity and energy. Instead, it allows the way in which the plant is used to determine how its capital costs are allocated. A nuclear unit, for example, is a base-load unit with very high capital costs, almost all of which are energy-related, and very low variable costs. Under the P&A method, a rate class with significant use on peak and little use off-peak would be assigned a relatively large share of the capital cost of the unit, since 40 percent of the capital cost would be attributable

to capacity. Under the POD method, however, the result would be different.

The POD method would allocate the capital costs of the nuclear unit to each hour in which it was likely to operate. Since a nuclear unit is a base-load unit, it would run in a large number of hours. This means that any one hour would receive a relatively small allocation of the plant's cost. Thus, a rate class with most of it use during peak hours would be assigned a relatively small portion of the plant's cost. A rate class with level use in all hours, however, would be allocated a larger portion of the plant's costs since it would use the plant in all hours. This is as it should be. The higher capital costs of the plant (<u>i.e.</u>, over and above the cost of a peaker) were incurred to lower energy costs. It would not be proper to take those higher costs and allocate them on peak demand, since they were not incurred to meet peak, but rather to provide lower energy costs.

A similar situation holds with peaking units. Under the P&A method, a rate class with relatively level use in all hours would be allocated a relatively large proportion of the plant's capital cost, since 60 percent of the cost would be allocated on energy. A peak-intensive rate class, however, would inappropriately be allocated a smaller portion of the plant's capital cost under the P&A, since only 40 percent would be allocated on a capacity allocation related to peak use.

Under the POD method, however, the peaking plant's capital cost would be assigned only to the hours in which it runs, that

is, peak hours. A rate class with level use would then be allocated relatively less of the costs, since only a very small portion of its use takes place in peak hours. The more peak-intensive rate class, however, would appropriately be allocated a much larger proportion of the costs, since its peak use makes up a large portion of its total use.

The results for both base-load and peaking plants using the POD method are not counterintuitive, as suggested by the City. The capital costs are allocated based on the reasons behind their cost incurrence. Further, under the POD method, rate classes are allocated costs for a plant directly in proportion to the benefits they receive from that plant, since the costs are based on their share of the use of the plant.

These are the reasons we have found the POD allocator to be a better allocator in the past and the reasons why we maintain that finding here. The Consortium and City premise their contentions on the fact that the POD allocation factors are similar to the energy allocation factors. Unfortunately, the conclusion they draw from this fact, that the POD must be wrong, is itself incorrect. The results of the POD do not show it is wrong; rather, as the Company's witness pointed out (Tr. 18, pp. 2140-2144), it shows that the P&A method has been wrong because it presumes too high a percentage of the capital cost of the Company's units in aggregate to be capacity-related. It would be incorrect to determine that, since the results of the method do not match a preconceived notion of what the results

should show, the method is wrong. Rather, an analysis of the POD method versus the P&A method reconfirms our determination that the POD method results in a more accurate allocation of costs.

The Consortium maintains that the POD method could be improved. It proposes that the capital costs of a unit not be assigned to all hours in which the unit has a probability of running, based on the dispatch model, but instead be assigned only to the number of hours which were necessary to make the unit cost-effective compared to intermediate or peaking units. We find, however, that this so-called capacity factor method would lead to an incorrect result.

If costs were assigned only to the hours which were needed to make the unit cost-effective, beginning with the highest load hours, some low-load hours would not be assigned any portion of the capital costs of any units. Yet those hours, and the rate classes which use electricity in those hours, would still be getting benefits from the capital costs incurred. This is because the low variable costs which exist in those low-load hours exist only because the utility built a unit with high capital costs, most of which were necessary to produce the low variable costs. If such rate classes are not allocated a portion of the capital costs, they are not allocated the costs required to provide them service. The capacity factor variation of the POD method, then, necessarily mismatches costs and benefits. For these reasons we reject the Consortium's proposal

that the Company be required to file a COSS based on this method in its next rate case.

Accordingly, the Department finds that the POD allocator used in this case is appropriate and reasonable. The Department, however, recognizes that the POD model involves many complicated inputs and is difficult to review. Indeed, this is evidenced by the parties' cross-examination of the Company's witnesses and their arguments on brief. Ease of review, which comes from simplicity in method, is an important factor in choice of allocators. The Department seeks use of allocators which are the simplest allocators which correctly allocate costs. As we have found in this case,the POD correctly allocates costs, but it is not a simply calculated allocator. We would prefer a simpler allocator if it could be shown that it results in allocations which are essentially the same as the POD. The Company, therefore, is instructed, in its next rate case, to file (1) a COSS using the POD method; (2) a report investigating alternative methods that capture the essence of the POD allocation but are simpler and more easily computed and understood, and (3) a COSS based upon an alternative method.

D. Allocation of Revenue Requirement

Once the Company has completed the cost allocation process, it determines the difference in the rates of return ("ROR") for each class by comparing the total class revenue requirement computed in this case with the total revenues from each class in the test year.

The Company states that rates of return should be equalized in this case (Company Brief, pp. 296-298). The Consortium agrees that the Department should complete the process begun in D.P.U. 1350 and fully equalize the rates of return between each rate class (Consortium Brief, pp. 3-4). The City argues that ROR should not be equalized because of the impact which such equalization would have on the streetlighting class. According to the City, the increase that the streetlighting class would be subject to would violate the principle of rate continuity (City Brief, pp. 5-6).

The Department's policy is that system costs should be allocated on the basis of equalized ROR. The Department has also recognized that there should be continuity in rates and, therefore, has taken a gradual approach to the full equalization of the ROR that each rate class provides (D.P.U. 1720, pp. 120-131).

The City's argument suggests that the production allocator used in this case has the effect of violating our continuity goal for streetlighting classes if ROR are equalized. The City claims that if the Company were to be granted the full amount of its requested rate increase, and if ROR were equalized, the base rates would increase for streetlighting customers by an average of 13.81 percent (City Brief, pp. 19-20).

The City's position is incorrect for two reasons. First, the City considers only the change in base rates and ignores the impact of the fuel adjustment charge on the total bill. When

the Department considers continuity in rates, it seeks to avoid any unacceptable discontinuities in terms of total bill impacts. Continuity means that the rate structure changes should be made in a predictable and gradual manner which allows consumers reasonable time to adjust their consumption patterns in response to a change in rate structure. This requires consideration of the entire bill, including the fuel charge, which has been reduced substantially over the past year. Boston Edison Company, D.P.U. 86-1A, 86-1B (1986).

The City's argument is also premised on an overestimation of the percentage increase in base rates which will result from this case. The Company's rate increase is substantially reduced from the levels it initially requested, thus reducing the impact of the reallocation process on each rate class.

Based on our review of the bill impacts resulting from equalization, we find that equalizing ROR in this case will not violate our continuity standard for any rate class. Accordingly, we find that ROR between classes should be equalized in this case.

The Company shall allocate its allowed revenue requirement as shown on Schedule 10. Schedule 10 allocates the Company's allowed revenue requirement to the Company's various rate classes. The schedule allocates to each class the same percentage of the total revenue requirement as it was allocated in the Company's pro forma COSS which used equalized ROR. The SSI revenue deficiency is allocated to the rate classes using

each class' percentage of the total retail rate base.

It is conceivable that the allocation of the disallowed expenses may differ from the percentages used in allocating the revenues. If this is in fact the case, the ROR of each class would not be exactly equal. However, the proportion of the expenses that the Department has disallowed, when compared to the Company's total revenue requirement, is very small. Further, the allocations to rate classes change between rate cases because of changes in load patterns. Therefore, the Department finds that the amount of the error is de minimis and the allocation method used in Schedule 10 is acceptable.

X. RATE DESIGN

A. Rating Periods

One of the most important aspects in determining marginal costs is the determination of time periods to be used in establishing costs and, eventually, rates. There are two types of periods which are used in designing rates. The first is the costing period, which refers to the time periods in which costs, in this case marginal costs, are determined. The second type of period is the rating period, which refers to the time periods for which rates are set. The Company used an hour-by-hour dispatch to determine marginal energy costs; thus, the costing period was each hour. It then averaged the hourly marginal costs by rating period to determine the marginal cost of energy in each rating period. Marginal capacity costs were determined to exist only in the peak period.

The Company's existing rates have both seasonal and daily rating periods. Its two seasonal periods are summer (July, August, September and October bills to capture the summer costing period of June through September and winter (all other months). Its daily rating periods are: peak, 8:00 a.m. to 9:00 p.m. EST (9:00 a.m. to 10:00 p.m. EDT) weekdays; off-peak, 9:00 p.m. to 8:00 a.m. EST (10:00 p.m. to 9:00 a.m. EDT) weekdays and all hours weekends and holidays. BECo reviewed each of these periods to determine whether they continued to be valid.

The Company reviewed its seasonal rating periods by examining its annual system peak. It argues that annual system

peak is a prime determinant of cost because (1) it determines overall investment in fixed capacity and associated O&M expenses, (2) it is a major component in the NEPOOL formula which determines the Company's capacity responsibility for pool purposes, which also drives the Company's capacity costs, and (3) it has an impact on system capability which causes the Company to incur marginal capacity costs (Exh. BE-300, p. 9). Examination of historical data indicates that the Company's calendar year annual peak has occurred only in its summer period in each of the last 15 years. The annual peak is also projected to remain in the summer period for the foreseeable future according to the Company. For these reasons, the Company states, its present seasonal rating periods are appropriate (Exh. BE-300, p. 10).

The Company analyzed its existing daily rating periods using a statistical technique to maximize the difference between groups of hours and minimize the difference within groups of hours. It analyzed system load, total fuel cost, and marginal energy cost in this manner. It found that the statistical results could be improved if the peak period was begun one hour earlier, i.e., 7:00 a.m. instead of 8:00 a.m. The Company decided not to increase the peak period, however, based on the administrative decision that such a change would dilute the peak-period price signal. No party objected to the Company's proposal (Company Brief, p. 265; Exh. BE-300, pp. 11-12; Exh. BE-306).

One of the most critical decisions a utility must make is the rating periods it will use for pricing the sale of its product. We find the Company's rating period proposals to be the result of objective analysis and sound judgment. The Company conducted statistical tests of three major measures of cost incurrence: load, fuel costs, and marginal energy costs. The statistical results showed that the present rating periods were sound, but that the statistical results would be improved by increasing the peak period by one hour. Because it judged that a further broadening of peak hours would reduce the peak-period price signal, the Company elected to maintain its present rating periods. Since the Company has conducted an objective analysis and tempered the results with explained, reasoned judgment, we find the rating periods which the Company proposes to be acceptable.

B. Marginal Costs

1. Marginal Capacity Costs

a. Production

i. Description

The Company determined its marginal production capacity costs ("MPCC") using the modified peaker method. The purpose of the calculation is to determine marginal capacity costs by determining the present value of the revenue requirements associated with 1 KW of capacity. (The modified peaker method calculates the capital cost of a peaking unit in the year it is needed for capacity purposes and then discounts that cost back

to the present.) The Company used 1988 as the year in which it needs capacity. In this case, the Company escalated current-year plant costs to 1988 and then discounted the costs to the present using the Company's marginal cost of capital. It adjusted this amount by a general plant loading factor and then multiplied the result by an economic carrying charge ("ECC")[20/] rate and an administrative and general ("A&G") loading factor. To this amount it added capacity-related operation and maintenance costs adjusted by the A&G loading factor. Then, an amount was added to account for the cost of working capital associated with the investment. Finally, this amount was increased by 18 percent to account for the Company's required reserve margin. The result was the annual revenue requirement associated with the investment in the plant (Exh. BE-305, Sch. 1, pp. 1-2, Sch. 6, pp. 1-2).

Capacity-related production costs were assigned to the summer and winter rating periods using an economic discount method ("EDM"). Within the seasonal rating periods, MPCC were

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20/ The economic carrying charge rate converts the cost of an investment of $1,000 to the revenue requirement necessary to support the investment using factors for AFUDC, depreciation, and tax effects, over 30 years, and discounts the revenue requirement stream at the Company's marginal cost of capital to determine the present value of the revenue requirements. It then converts this present value to an economic carrying charge rate, using a standard formula which includes the Company's marginal cost of capital, inflation net of technological progress, and projected service life of the investment.

assigned to daily rating periods based on the loss of load probability ("LOLP"). This resulted in all MPCC being assigned to peak hours (Exh. BE-305, pp. 12-17).

Four issues have been raised regarding the Company's calculations: (1) whether the costs were assigned to rating periods in a proper manner; (2) whether the previously established modified peaker method is the appropriate way in which to determine MPCC; (3) whether the Company's calculation appropriately stated costs as of the day after rates could be in effect; and (4) whether the marginal or embedded cost of capital should be used in the study.

ii. Assignment of MPCC to Rating Periods

The EDM first calculates the number of years the winter and spring/fall peaks lag behind the summer peak. The cost of the peaker is then discounted for each of these seasonal periods by the number of lag years. This provides the relative marginal cost of capacity by season. The actual MPCC is then assigned to each season in proportion to that season's share of the sum of the MPCC by season (Exh. BE-305, pp. 15-16).

For example, in this case the Company determined that the winter peak lagged 5.7 years behind the summer peak while the spring/fall peak lagged 13.4 years behind. If the marginal cost of a peaker is assumed to be \$100 (the actual number does not affect the calculation) and the discount rate is 13.37 percent, then the relative seasonal marginal costs would be \$100 for the summer, \$48.90 for the winter ($\$100 / 1.1337^{5.7}$), and \$18.61

for the spring/fall ($100 / $1.1337^{13.4}$). The total of these seasonal marginal costs is $167.51. Of this total, the summer is 60 percent ($100 / $167.51), the winter 29 percent, and the spring/fall 11 percent. When aggregated into just two seasons, this process assigns 60 percent of the MPCC to the summer and 40 percent to the winter/spring/fall period.

The LOLP assigns costs to hours based on the probability in each hour that the load in the hour will exceed the available capacity of the Company. On a seasonal basis, this method assigns costs based on the sum of the hourly probabilities in each season as compared with the annual total of the probabilities. Use of this method would assign 39 percent of the marginal costs to the summer and 61 percent to the winter (Exh. BE-305, p. 15).

The Company examined four possible methods for assigning costs to seasons. The criteria it used for evaluating these methods were stability, flexibility, and practicality (Exh. BE-305, pp. 12-17). "Stability means that overall costs to the rate classes should change in gradual fashion from rate case to rate case" (id., p. 17). "Flexibility means that a method can easily handle changes in the rate making and regulatory arena" (id.). "Practicality means that ... [a] method that yields the 'wrong answer' in the sense of common business practice or fairness to the customer should be judged as inadequate" (id., p. 18).

As a result of applying these criteria to the methods

evaluated, the Company concluded that the best method for assigning costs to seasons was the EDM and that the best method for assigning costs within seasons was the LOLP. The Company found that "[t]he LOLP method gives the best results for hourly allocation, and the problems associated with it may be minimized as long as comparisons are on similar day types only and do not cross seasonal boundaries" (id., p. 17).

The Attorney General argues that LOLP is a better indicator of when the Company needs capacity. According to his witness, Ms. Geller, many hours drive the need for capacity and, because of this, "all hours except those with zero LOLPs should be allotted some marginal capacity cost" (Attorney General Brief, p. 141). He states that the Department has recognized that capacity does have value in the spring and fall, that the LOLP indicates that this is the case, and that the LOLP should be used to assign the marginal costs (Attorney General Brief, pp. 142, 146). No other party took a position on this issue.

The Company argues that the EDM represents the best method for assigning costs to seasons because it produces the most stable results over time. The LOLP method, advocated by the Attorney General, has two major problems, according to the Company. First, it does not track the size of unserved load, but instead tracks hours of high energy costs. All hours with high energy costs do not necessarily indicate a need for capacity, the Company maintains. Second, the Company states that spring and fall hours show up as having LOLP because the

Company is doing maintenance on its units, not because it is actually short of capacity (Company Brief, pp. 260-261). The Company concludes that this would result in capacity costs being assigned to these seasons even though the Company does not actually need capacity at that time.

The Attorney General makes his arguments for using the LOLP in connection with the elimination of demand charges and with regard to the Company's interruptible rate proposal. He does not address the Company's arguments regarding the EDM directly. Basically, he argues that if the Company needs capacity as measured by the LOLP, then marginal capacity costs should be assigned to those hours (Attorney General Brief, pp. 142, 146).

We find that the LOLP method has major deficiencies when used to assign marginal costs to seasons. Although it tends to track hours of high energy use, and indicates that load is going unserved, it does not measure the size of the unserved load, i.e., the amount of capacity by which the Company is short in a particular hour. It just totals the hours that the Company is short of capacity. The size of unserved load is critical, since a deficiency of one MW has vastly different consequences than a deficiency of 100 MW. One MW can easily be obtained from the power pool and would not necessarily indicate the need for additional capacity. A deficiency of 100 MW, however, would indicate that additional capacity may be necessary and thus that the Company is incurring marginal capacity costs.

Additionally, because the Company has units out for

maintenance in the spring and fall, those hours show up as being short of capacity using the LOLP. From a planning perspective, however, they are not capacity-short in those hours since maintenance is scheduled for the hours where there is adequate capacity from other sources. Additionally, maintenance schedules provide the flexibility necessary to have units available to meet the projected loads. Thus, we conclude that the use of the LOLP to assign capacity costs to seasons for ratemaking purposes would be inappropriate. In contrast, the EDM results in more stable and reliable results for seasonal assignments. Accordingly, we find that the use of the EDM for assigning marginal capacity costs to seasons is appropriate.

The LOLP does have value, as recognized by the Company, in assigning costs to daily rating periods. Almost all of the LOLPs occur during the Company's peak hours. Indeed, LOLP is related to one of the measures used to determine peak hours, and so it is not surprising that the correlation between LOLPs and peak hours occurs. We find that the use of LOLP for assigning marginal capacity costs to daily time periods is appropriate. Further, it should be one of the factors examined when the Company periodically reviews its daily rating periods.

iii. Use of the Modified Peaker Method to Determine MPCC

The Company used the modified peaker method as required by Department precedent, but it contends that a next-unit/fueloffset method[21/] is better, but "[s]ince the

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21/ The next-unit/fuel offset method takes the next generating unit the company plans to bring on line and calculates the present value of the capital cost of one KW of that unit net of fuel savings.

Company's resource plan is no more concrete than it was during DPU 1720, the Company did not file a fuel offset study here" (Company Brief, p. 255). It states that the modified peaker method yields the most accurate determination of costs given these circumstances (Company Brief, pp. 254-255).

The Attorney General proposes a next unit-method which differs from the Company's proposal in two respects: the portions of capital costs attributable to capacity and energy are not distinguished, and a levelized carrying charge rate is proposed instead of a year-by-year economic carrying charge rate (Exh. AG-SG-1, p. 24; Tr. 24, pp. 3275-3284).

No other party took a position on this issue.

The next-unit/fuel offset method advocated by the Company would determine the portion of capital costs associated with capacity as the portion of capital costs not covered by savings in energy costs. In the planning process this estimated amount will always be less than or equal to the estimated capital costs of a peaking unit.22/ This is because a peaking unit, which has no energy savings, has all of its capital costs associated with capacity. The only reason a company would build a unit other than a peaking unit is if the capacity-related capital costs were less than the capacity costs of a peaking unit. This is the result because utility projects are evaluated on a

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22/ We note that, in recent history, the capital costs of several base-load nuclear units were grossly underestimated by planners and so the actual cost result does not necessarily comport with the planners' attempt to achieve a least-cost system. See Fitchburg Gas and Electric Light Company, D.P.U. 84-152 (1985); Western Massachusetts Electric Company, D.P.U. 84-25 (1984).

total-cost basis and, using the next-unit/fuel offset method, capacity-related capital costs for a nonpeaking unit can be lower than the same costs for a peaking unit only if the total costs are lower.

One possible result from the next-unit/fuel offset calculation is that the next unit could have negative capacity-related capital costs if the energy savings outweigh the total cost of the plant. (Indeed, some nuclear units were held out by the companies as offering this promise.) The Department, however, has recognized that units do have positive capacity costs and that such costs should be reflected in rates to customers and to qualifying facilities ("QF"). In D.P.U. 84-276-A, the Department has proposed that the next-unit/modified peaker method be used to determine the rates for QFs. The portion of the capital costs related to capacity would be determined by the costs associated with a peaking unit brought on line in the same year. The remaining portion of capital costs would be classified as energy-related.

In this case neither the Attorney General nor the Company has stated a view as to how next-unit capital costs ought to be assigned to capacity and energy. The Attorney General's witness,since she supports the elimination of demand charges, would require this determination only to calculate the reliability-related position of the plant whose cost would be assigned to peak period KWH (Tr. 24, pp. 3281-3282). The Company has not explicitly stated a position regarding how the

capital costs should be split. Thus, though the parties raise the issue on brief, there is insufficient evidence on this record to determine how the capacity portion of the capital costs of the next unit should be calculated. Such a calculation is not required in this case because no next-unit method calculation has been filed in this case. We request the parties to address, in the Company's next case, the issue of the method by which the capacity and energy portions of capital cost should be determined, given the calculations of long-run marginal energy cost as discussed below.

In this case, there are calculations of MPCC using the modified peaker method. Since this method is available and conforms to Department precedent, it shall be used to determine MPCC in this case.

iv. Calculation of Marginal Capacity Costs as of the Date Rates Go into Effect

The Company, in its original filing, calculated marginal capacity costs as of the end of 1986. The Department found in D.P.U. 84-165-A that marginal costs should be determined as of the date on which rates go into effect. Id., p. 45. No party contested a calculation which uses the day after rates could be in effect.

Consistent with the precedent established in D.P.U. 84-165-A, therefore, we find that marginal capacity costs should be adjusted to the date rates go into effect.

v. Use of Embedded vs. Marginal Cost of Capital

The cost of capital is determined by the percentage of each

component of the capital structure as a whole and the rate of return for each of the components. The Company calculated a marginal cost of capital using embedded returns on its debt and equity capital, but it did not use embedded capitalization ratios. Instead, the Company based its capitalization ratios on the Standard and Poor's bond rating criteria for a single-A rating (Tr. 19, pp. 2423-2425). The Company explained this procedure by stating that, since it planned to try to approach the capitalizations ratios required by Standard and Poor's for a single-A rating and since a marginal cost study should be forward-looking, it was appropriate to use its projected marginal capitalization ratios.

No party took a position on this issue.

In this case, the basis of the Company's adjustment is not adequately supported. The adjustment to the capitalization ratio is speculative. The Company has made adjustments to the rates of return of the various components, based on known and measurable changes, in the capital structure used to determine the embedded cost of capital in this rate case. Yet it did not make those adjustments to the cost of capital used in its marginal cost study. While we do not require as strict a known and measurable standard for marginal cost studies, we cannot accept a calculation which contains a speculative adjustment on the one hand and ignores known and measurable changes on the other. For this reason, the marginal cost of capital computed by the Company cannot be found to be more accurate than the

embedded cost of capital. Therefore, we find the embedded cost of capital shall be used.

Exhibit HO-RR-27 contains the calculation of MPCC which uses the modified peaker method and an embedded cost of capital, and calculates the marginal costs as of the date rates go into effect. We find that this is the appropriate measure of marginal cost for the purposes of this case. The calculation of the MPCC and the assignment to seasons are shown on Schedule 13.

b. Transmission

The Company distinguished between two types of transmission capacity costs. The first group represents costs associated with bulk transmission connected with the generation function. It stated that since these costs "are incurred to take advantage of lower fuel costs associated with large baseload units located away from the load center ... investment in these facilities is captured thorough the generation reserve adjustment and by pricing all KWH at the marginal energy cost ..." (Exh. BE-305, p. 4). For this reason the Company excluded these types of transmission costs from its calculation of marginal transmission capacity costs ("MTCC"). The second, remaining group of costs relates to local transmission facilities that are used to feed the distribution system. The costs associated with these facilities were used to determine MTCC.

The Company derived its MTCC by determining for each transmission account the increase in investment over the prior year for a 25-year period. This period comprised historical

data for 20 years and projected data for five years. The cumulative change in the grand total of the accounts by year was then regressed against transmission peak loads by year to provide a long-run unit investment per KW of transmission capacity. BECo then adjusted this cost by the economic carrying charge for transmission; and by the A&G, O&M, and working capital loaders applicable to transmission. The MTCC were then assigned to rating periods using the same assignment factors used for production (Exh. BE-305, pp. 4-5; Exh. BE-305, Sec. IX, MCWS-10, MCWS-100).

There is one issue regarding the calculation of MTCC: whether projected data should be included in the regression to determine MTCC.

The Company does not take a position regarding whether the use of projected data is appropriate. It does request that, if the Department finds that only historical data are appropriate, it should state whether the finding is based on the particular data used in this case or on general grounds (Company Brief, p. 259). No other party took a position on this issue.

Where historical data have shown that there is a strong relationship between the level of a company's investment in transmission plant and the changes in loads experienced by the company, the use of historical data is preferable. The historical data are known and measurable and the existence of a strong relationship implies stability in their use. Further, even though loads may be projected with some accuracy,

projection of budgets is the subject of more uncertainty and so such data should not be used to determine the regression relationship. Therefore, we find that where a strong relationship between expenditures in plant and changes in load can be shown statistically, as in this case, only historical data should be used unless the Company can demonstrate that significant changes are going to occur.

Based on the foregoing finding, and the findings above regarding assignments of costs to seasons, calculation of costs as of the date rates go into effect, and the use of the embedded cost of capital, we find that the appropriate measure of MTCC is found by conducting a linear regression of the historical data found in Exhibit HO-RR-27, p. 5, and using the resulting $/KW in the calculation of MTCC shown on page 2 of that exhibit. The regression results are shown in Schedule 11. The MTCC is calculated in Schedule 13.

c. Distribution

The Company derived its marginal distribution capacity costs ("MDCC") in essentially the same manner as it used for MTCC. The only differences were that (1) ten historical and five projected years were used (instead of 20 historical and five projected) and (2) the costs were developed for two voltage levels, high-tension and secondary. Certain accounts which contained investments at both high-tension and secondary voltages were split between high-tension and secondary based upon their percentages of plant, determined through sampling of

continuing property records (Tr. 19, pp. 2427-2429).).

These basic costs were then adjusted by loading factors and the economic carrying charge rate in a manner analogous to MTCC. The resulting high-tension and secondary distribution costs were then assigned to rating periods using the inverse of the difference between loadings and capacities on the distribution circuits. This resulted in a 40/60 summer/winter split (Exh. BE-300, pp. 6, 8; Exh. BE-305, p. 17, sec. 10, MCWS-1010; Company Brief, p. 261).

No party disputed the Company's calculations. The only issue in this calculation is the use of projected costs in the regression analysis to determine marginal costs. Our analysis and findings on this issue in the case of MTCC are equally applicable here since the methods are, in all relevant aspects (i.e., based on a linear regression of cumulative changes in plant investment against cumulative changes in load), the same. We find, therefore, that the appropriate measure of MDCC is found by conducting a linear regression of the historical data found in Exhibit HO-RR-27, p. 7, and using the resulting $/KW in the calculation of MDCC shown on page 2 of that exhibit.

The regression results are shown in Schedule 12. The MPCC is calculated in Schedule 13.

2. Marginal Energy Costs

a. Description

The Company, in its filing, calculated only marginal production energy costs, asserting that it had no marginal

transmission or distribution energy costs. No issue was raised regarding this aspect of the filing, and we will use the term "marginal energy costs" to mean marginal production energy costs in this discussion.

The Company determined its marginal energy costs for each rate class by first calculating the marginal cost for each rate class at the generator for each rating period. Second, the line loss factor for each voltage level within each rating period was also determined. Finally, to determine the marginal energy cost for the class, its cost at the generator in each rating period was multiplied by the appropriate line loss factor for the rating period based upon the predominant voltage level at which the class is served.

BECo determined the marginal energy costs at the generator for each rating period using the POD model described above. The inputs used by the Company were test year load and fuel costs, and the normalized availability of units using the Department's performance goals. The model then calculated the marginal cost for the system in each hour. A weighted average marginal cost for each class was determined by using the KWH loads of the class in each hour as the weights in calculating the marginal cost per KWH for each rating period. Since each class has different proportions of use in each hour within a rating period, the marginal costs for each class within a rating period are different (Exh. BE-305, Sch. 4 (MCWS-600); BOS-23; Tr. 18, pp. 2206-2210).

The Company was asked to run a study keeping all factors the same except the load and fuel prices. For these inputs, the data from the most recently available twelve months (ending January 1986) were used (Exh. HO-RR-10).

There are two issues regarding marginal energy costs: (1) whether they should be determined over the short run or long run, and (2) whether the costs used for rates should be calculated specifically for each class or for the system by voltage level.

b. <u>Short-run vs. Long-run Marginal Energy Costs</u>

The Attorney General argues that marginal energy costs should be calculated over a long-run timeframe. Although the Company uses short-run costs to determine marginal energy costs in compliance with D.P.U. 1720, the Attorney General states that the use of such short-run costs is not consistent with more recent Department Orders. The Attorney General maintains that the Department has stated that all forms of electric supply (utility-owned generation, QF, and conservation) should compete on an equal footing. He states that the Department recognized in D.P.U. 84-276-A that the use of short-run marginal energy costs for QF rates will not provide that equal footing and decided that long-run marginal energy costs are appropriate for setting QF rates. He argues that the same rationale is applicable to conservation, which means that long-run energy costs should be used to set the rates utilities charge customers (Attorney General Brief, pp. 129-134).

According to the Attorney General, long-run marginal energy costs should be calculated in the following manner. The Company should determine the marginal energy costs for each year over a sufficiently long period (greater than twenty years). Once having determined the costs for each year, those costs would be discounted to the present and then levelized over the period of the forecast to determine the levelized cost per KWH. To determine the marginal energy cost in each year, the Company would run its production cost model. The cost for the year would be the higher of (1) the marginal cost determined by the model or (2) the variable cost plus capitalized energy cost of the most recent generating unit added, looking only at unit additions which occur in the future (Tr. 24, pp. 3280-3283; Exh. AG-SG-1, p. 26).

The Consortium argues that energy rates should not be based on long-run marginal energy costs. It maintains that the Department has already rejected the use of long-run marginal energy costs in Fitchburg Gas and Electric Light Company, D.P.U. 84-145-A (1985). The Department's recognition of capitalized energy costs in D.P.U. 84-276-A was for a limited purpose, the Consortium argues; specifically, the calculation of a ceiling price schedule for QFs. It states that the actual rates paid to QFs will be less than the projections of long-run marginal energy costs, and that the regulations would require the bidder to provide security to the utility and ratepayers if payments are front-loaded. Even with front-loaded payments, the

Consortium maintains, there is a crossover point where the QF will receive less than the marginal capacity and energy cost at that point in time. The Consortium argues that the Attorney General's proposal does not provide security to ratepayers for the near-term subsidies of conservation which result from front-loaded payments and, since long-term rates would be recalculated every time there is a rate case and thus re-front-loaded, a crossover point would never be reached. The Consortium concludes that the Attorney General's proposal would grant conservation an unwarranted, non-cost-based subsidy and so should be rejected (Consortium Reply Brief, pp. 4-9).

The Company states that it is appropriate to use short-run marginal energy costs. It claims that use of the modified peaker method for capacity costs recognizes long-run costs through the peaker calculation itself. Further, the Company maintains, even if long-run costs are used, the Attorney General's proposal to use levelized carrying charge rates would continually overstate the long-run marginal energy cost (Company Brief, pp. 257-259).

No other party took a position on this issue.

The Department has previously stated that it "recognizes the need to give customers a price signal regarding a utility's long-run cost of capacity." D.P.U. 84-145-A, p. 103. We have also declined to price energy at long-run marginal cost because no method has been proposed in past cases which has complementary methods of determining long-run capacity and

energy costs. Id.

As the Attorney General points out in this case, the Department has, through the proposed QF rules, developed a method of determining long-run marginal energy costs which is complementary to the modified peaker method of determining long-run capacity costs. In the proposed QF rules the Department has recognized and developed a method for segregating the portion of capital costs related to capacity and the portion related to energy. The question remains whether long-run energy costs or short-run energy costs are more appropriate for setting customer rates.

From an operating perspective, once a plant is "sunk," the energy cost of that plant consists only of the variable costs of the plant. As the Attorney General points out, however, the utility industry is characterized by long-run planning horizons. He argues that since the utility's investment decisions are based upon long-run, not current, costs, all sources of supply should be considered on that long-run basis. Unless utility rates are based on long-run costs, he maintains, a major source of future energy, conservation, will not be on an equal footing with other sources of supply since its price signal, utility rates, will have a different basis from other supply sources.

The Department has stated that, in order to achieve a least-cost basis for energy, all sources of supply must be considered on an equal footing. The reference point in all of

these discussions is least-cost supply, that is, the utility should plan its investments in generation, conservation, and small power production and cogeneration so that it may supply power to customers at the lowest cost. This means that conservation engaged in by the Company must be placed on an equal footing with other sources of supply. It does not mean that rates charged to customers must be on the same footing.

The appropriate basis for rates, as we have stated many times, is marginal cost. A marginal-cost-based rate design provides customers with accurate price signals regarding the cost of their consumption and enables them to determine their level of use appropriately. We have reflected marginal costs in rates in a manner which reflects how the Company incurs them, i.e., capacity costs are incurred in the long run and energy costs in the short run.

Historically, companies have incurred energy costs on a short-run basis. Under the proposed QF rules, however, companies would sign long-term contracts with essentially fixed energy rates. This changes the basis on which a company incurs energy costs from strictly short-run to both short-run and long-run. Additionally, as we stated in D.P.U. 1720, "[i]f marginal costs vary significantly and predictably as a function of time, then more accurate price signals will be given if the rate design reflects those variations." Id., p. 117. That statement is applicable not only to variations within days or seasons, but across years. Previously, marginal energy costs

did not vary in a predictable manner. With the advent of contracts with fixed energy rates, however, the costs incurred by the Company for energy do vary predictably in the long run. For these reasons it is now appropriate to reflect long-run energy costs in rates. Therefore, we find that, generally, the marginal energy costs upon which utility rates are based must be long-run costs unless there exist overriding factors.23/

We are concerned that one such factor may be the effect of long-run energy rates on economic development in the Commonwealth. It is possible that as in the past, long-run energy rates could be significantly higher than rates based upon short-run costs. In such a case, rates for companies under the Department's jurisdiction may be significantly higher than rates for other companies based upon short-run or average costs. Large customers with substantial use have a number of options available to them with regard to their energy consumption. Higher rates may encourage them to conserve, or to install cogeneration equipment, or to leave the Commonwealth. We are

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23/ It is clear that any determination of long-run energy costs would require significant time for review. Such time, given other matters in a rate case, is limited. The proposed QF rules require that such determinations be made annually as part of the QF solicitation procedure. We would be inclined, therefore, to take the results of that procedure as the determination of long-run energy cost. We do not, at this time, determine how that should be done. Two possibilities are the utility's estimate of long-run costs or the highest accepted bid of the QF. We direct the Company to address in its next rate case how long-run energy costs should best be calculated using the results from the QF solicitation procedure. Therefore, we do not decide the appropriateness of levelizing long-run costs as the Attorney General proposes and the Company and Consortium oppose in this case.

aware that many jurisdictions already have significant amounts of excess capacity and are allowing electric utilities to offer economic development rates. We are concerned that use of long-run marginal energy rates, if long-run marginal energy costs are significantly higher than short-run marginal or average costs, may have undesirable side effects for the economic health of the Commonwealth.

If, indeed, there are found to be such undesirable secondary effects, one solution may be to use long-run marginal energy costs for rate classes whose customers use smaller amounts of energy and short-run marginal energy costs for rate classes whose customers use larger amounts. In the next rate case the Company and the intervenors should address the use of long-run marginal energy costs to set energy rates and its effects on the economic health of the Commonwealth. The Department requests that both the Company and the intervenors, in the next rate case, propose whatever alternative bases for marginal energy cost rate designs they believe appropriate if such a factor is of serious concern.

In this case we are unable to base rates on long-run marginal energy costs since there is no reliable estimate of these costs on the record. Further, the proposed QF rules have not been issued in final form and no estimate of long-run marginal energy costs for BECo has been reviewed in that context. There are, however, short-run marginal energy costs in this record which might be used. We will examine whether the

short-run marginal energy costs which are on the record can be expected to be significantly different from the long-run marginal energy costs which might be calculated.

There are three major factors which could cause long-run and short-run energy costs to differ: additions to capacity, increases in load, and changes in fuel prices. Additions to capacity tend to make long-run marginal energy costs lower than short-run marginal energy costs, even when including the portion of capital costs associated with capitalized energy. This is because a company would bring a plant other than a peaker on line only when the long-run variable energy costs plus capitalized energy costs are lower than the long-run variable energy costs of a peaker. Thus, plant additions, in and of themselves, tend to keep long-run marginal energy costs the same as or lower than short-run marginal energy costs.

Increases in load tend to make long-run marginal energy costs higher than short-run marginal energy costs. As the Attorney General points out, increased load, unless offset by increased capacity, causes more expensive plants to operate on the margin in more hours of the year, thus tending to increase long-run marginal energy costs above short-run marginal energy costs.

Changes in fuel prices can act to either increase or decrease long-run marginal energy costs as compared to short-run marginal energy costs. The direction in which they act depends on whether the predicted rate of increase in costs exceeds the

rate used to discount the future costs back to the present.

To the extent that changes in generating units and changes in load work in opposite ways, they tend to cancel each other out. Further, the effects of either of these occurrences are generally overwhelmed by the changes in fuel prices, i.e., these occurrences are very important only if fuel prices are forecast to remain essentially constant. Thus, it is fuel prices which demand the closest examination.

The Department is well aware that fuel prices, as well as forecasts of fuel prices, have decreased significantly since the test year. The forecast of fuel prices to the year 2010, as of October 1985, when discounted to the present, yields a price near the present price of fuel (Attorney General Brief, p. 136; Tr. 24, p. 3285). The most dramatic decreases in prices occurred after October 1985. A calculation of marginal energy costs based on test year prices would thus be higher than a calculation based on prevailing fuel prices and higher than a calculation based on a levelization of fuel prices projected for 25 years as of October 1985. A calculation based on the twelve months ended January 1986 could similarly be expected to be higher than a calculation based on present or October 1985 projected fuel prices since it would contain only two months of lower fuel prices. Finally, since oil prices have fallen since October 1985, it is reasonable to expect that forecast oil prices have also fallen, meaning that test year average or average of twelve months ended January 1986 prices could be

expected to be higher than most recent projections.

Thus, of all the oil prices, test year average is highest, followed in order by the average of twelve months ended January 1986, levelized prices calculated based on October 1985 projections, and levelized prices calculated based on most recent oil price projections. The difference in the fuel prices contained in these various alternatives is so great that it can reasonably be expected to overwhelm whatever possible increase in long-run marginal energy costs would result from increases in load. Therefore, we find that the use of the marginal energy costs calculated based on the twelve months ending January 1986 (contained in Exhibit HO-RR-10) is reasonable since it is not likely to result in a measure of marginal energy costs which is significantly lower than a measure based on long-run costs. For these reasons, this measure is appropriate and can serve as a basis for rate design in this case.

c. Marginal Energy Costs for Rate Classes: Class-Specific Costs vs. System Costs

In past cases before the Department, companies have calculated marginal costs for rate classes in a three-step process. First, they determined their marginal energy costs in each hour at the generator. Second, using the system KWH loads in each hour as weighting factors, they determined their marginal energy costs at the generator by rating period. Third, they used line loss factors which, when applied to the marginal costs by rating period at the generator, produced marginal costs by rating period for each of the voltage levels at which the

company provided service. This resulted in all classes at the same voltage level having the same marginal energy costs.

In this case the Company proposes to modify the three-step process slightly. Instead of using the system KWH loads as weighting factors in step two, they would, for each class, use the class' KWH loads in each hour to develop the weighting factors. This results in each class having a marginal cost for each rating period which is unique to it.

The Company argues that the Department should use class-specific costs because they more closely track the pattern of class cost incurrence. It states that the data, while not easily obtainable, are already calculated for COSS purposes and therefore represents no additional burden to obtain and use (Company Brief, p. 256).

No other party took a position on this issue.

The Company would have the Department base energy rates for rate classes upon the specific load pattern for each class. Except for the streetlighting classes, all of the class-specific rates are within $.0015 per KWH of the system marginal cost.[24/] As the Company's witness pointed out, the differences would become larger as the difference between oil and nuclear KWH become larger (Tr. 18, p. 2208). There is no

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24/ Since installed lights are not amenable to marginal use, i.e., they are either on or removed, the marginal energy price signal has significance only when comparing the choice between types of lights, not to the consumption of an existing light. An existing light will be charged what amounts to a fixed price per light since energy consumption is constant.

evidence on this record, however, to indicate that the additional effort on the part of the intervenors and Department to verify these additional calculations is justified by the differences in the resulting charges in this case. Therefore, we find that in this case the system marginal cost at the generator, adjusted by marginal losses by time period and voltage level, is appropriate to determine the marginal energy costs for each rate class. If, as a result of the use of long-run energy prices or changes in the relative prices of oil- and nuclear-fired KWH, the Company believes the difference has become significant, it may raise the issue for further consideration in a future docket.

3. Marginal Customer Costs

Marginal customer costs were determined for each individual rate class by calculating the investment in services and meters for each class and computing the annual levelized revenue requirement, per customer, associated with each investment in a manner similar to that used for marginal capacity costs. No party disputed the Company's calculation of marginal customer costs as shown in Exhibit BE-305, and we find them to be reasonable.

XI. RATES

A. The Conversion of Marginal Costs to Rates

Once the marginal costs are determined, they must be reflected in the rates for each rate class. The Company developed its marginal-cost-based rates in accordance with Department precedent. It determined the voltage level at which each class was served, multiplied the seasonal marginal costs for that voltage level by the appropriate seasonal coincidence factor for the class, and summed the marginal costs by KWH and KW to determine the marginal-cost-based rates. Because the marginal costs produced in its study did not, when charged as rates, produce the revenue requirement computed by the Company for any rate class, the customer charge was increased so that the marginal-cost-based rate design would produce the revenue requirement for each class (Exh. BE-302A).

The Company then examined the resulting rates to determine whether they violated the goal of continuity. The customer charges required to meet the revenue requirement for each rate class under marginal-cost-based rates were so large that smaller-use customers in each rate class received rate increases which the Company believed violated the goal of continuity. Therefore, it sought to modify the marginal-cost-based rates.

The Company made four adjustments to the rates. First, it limited the increase in the customer charge to 50 percent. Second, it increased the demand charge from one-third to one-half of the difference between the existing level and full

marginal demand costs. Third, it increased the energy charge to meet the class revenue requirement while maintaining the relative differentials between peak and off-peak marginal energy costs (Exh. BE-300, p. 14). Fourth, it increased off-peak marginal energy costs by a "distribution adder."

Mr. Saunders testified that the Company is concerned that the theory of marginal-cost-based rates is inconsistent with the cost allocation process (Tr. 19, pp. 2452-2454). The Company argues that if customers respond rationally to the marginal-cost-based rates by increasing off-peak energy consumption, the use of the POD allocator will result in more costs being allocated to the class because of that increased off-peak consumption. For production, the Company argues, this is not a problem because the difference between marginal and average off-peak costs would recover the additional production costs which would be allocated to the class. The Company argues that this does not happen in the case of transmission and distribution costs. The purpose of the adder was to reflect, in the off-peak energy charge, the Company's best estimate of the difference between the marginal costs and the additional costs per KWH which would be incurred as a result of increased cost allocation from the POD based on increased off-peak consumption (Exh. BE-300, pp. 13-14).

The Consortium argues that the Company's modifications to the marginal-cost-based rates are inconsistent with Department precedent. It contends that the Department has stated that the

proper manner in which to establish charges is to balance the goal of continuity with the goal of rates based upon marginal cost. While the Company's adjustments have attempted to take into consideration some of these factors, the Consortium states, its method is not predicated upon an explicit balancing of goals and so must be rejected (Consortium Brief, pp. 5, 29-30).

The Consortium also raises the question of intraclass continuity. It argues that the larger (in terms of individual customer demand and energy use) general service classes are more heterogeneous than the smaller general service and residential classes. As a result of this heterogeneity and the volatility of fuel costs, it states, the customer charge under marginal-cost-based rates has large swings which have a severe impact on the bills of smaller customers within each rate class. This volatility also affects large-use customers, the Consortium notes. The way in which this can be rectified, according to the Consortium, is to establish rate classes (or subclasses) based not only on voltage level, but also on size or load factor. It concludes that rate classes based on such considerations would be more homogeneous and would avoid the large intraclass swings which result from changes in the customer charge because of changes in marginal energy costs (id., pp. 5, 27-29).

No other party objected to the Company's general method of rate design.

There are two factors which caused the Company's justified

concern regarding continuity and marginal-cost-based rates. The first is the size of the revenue increase sought by the Company. The second is the relatively low marginal costs calculated by the Company. Based on our analysis and findings in previous sections of this Order, both of these factors have changed.

The revenue increase sought by the Company of approximately $35 million has been significantly reduced by the Department. As a result, the revenue requirement for each rate class is less than that used by the Company in designing its rates. Using strict marginal-cost-based rates, this has the effect of reducing the customer charge for each rate class.

The marginal costs calculated by the Company have also been changed as a result of this Order. The marginal energy costs have been reduced slightly by the use of more recent fuel price data. The marginal capacity costs have increased significantly as a result of the use of only historical data for the computation of marginal transmission and distribution capacity costs. The net result of these changes is that the rates based on these marginal costs produce a larger amount of revenue, excluding the customer charge, than the marginal-cost-based rates calculated by the Company. This further reduces the customer charge for each rate class.

As a result of these two changes, the Department finds that it is able to set rates at or near marginal cost, without violating the goal of continuity. Specifically, all residential

rates may be set at marginal cost with the remaining revenue requirement collected through the customer charge. For Rates G-1 and G-2 marginal-cost-based rates produce a negative customer charge. Since there is no evidence on the record regarding how such a charge should be handled and since the interface between Rates G-1 and G-2 is critical, the Department finds that its goals of continuity and earnings stability are best served by having a customer charge of zero instead of a negative customer charge. This means that for Rate G-1, which consists, in the Company's proposal, of only a customer charge and an energy charge, the energy charge is set to collect the revenue requirement of the class while maintaining the same ratio between summer and winter energy rates as calculated in the marginal-cost-based rates. For Rate G-2, which, in the Company's proposal, consists of a customer charge, demand charge, and a two block, hours' use energy charge, this means that energy rates are set at marginal cost and demand charges are set to collect the remaining revenue requirement while maintaining the same ratio between summer and winter demand charges as calculated in the marginal-cost-based rates. The resulting G-2 rate is also of such a level that the rate subcodes which the Company proposed be transferred to a new rate, G-2A, for continuity reasons can instead be transferred to G-2 without violating the goal of continuity. Finally, Rate G-3 can maintain continuity for its customers while still approaching marginal costs more closely than the Company's

proposal.

As a result of this approach, the demand charges for Rates G-2 and G-3 increase significantly. This has the effect, in general, of increasing (or decreasing by a smaller amount) the bills of lower-load-factor customers. In examining the bill impacts for these rates, the Department explicitly examined the impact of this rate design on lower-load-factor customers. Because of the elimination of the customer charge and minimum KW bill, the reduction in base rate energy charges from existing rates, and the reduction in the fuel charge since the test year, the effect of significantly increased demand charges on low-load-factor customers is mitigated sufficiently that the rates do not violate our continuity goal.

The problem of intraclass continuity raised by the Consortium is of concern to the Department as well as the Company. This problem affects the large rate classes more acutely, but is not an isolated problem. Large customers have other characteristics which make them unique as compared to smaller-customer rate classes. For this reason, we direct the Company to address the issue of rate class heterogeneity and intraclass revenue shifts in its next rate case and to propose remedies, if the problem exists, which it believes to be appropriate.

Issues raised by the parties with regard to specific rates are discussed in the following rate-specific sections. The Attorney General questioned the appropriateness of demand

charges. Since this issue affects several rates, we will address it before our rate-specific analyses.

B. Elimination of Demand Charges

The Attorney General argues that marginal generation and transmission capacity costs are better reflected in peak-period energy charges than in demand-metered rates. He suggests that a peak KWH charge will serve the Department's goal of efficient and accurate signalling of the cost impact of load pattern better than demand charges. He maintains that marginal generation and transmission capacity costs, when reflected in peak-period energy charges, give customers the incentive to control their demand every hour of the peak period. Demand charges, he states, give customers the incentive to shift loads off their own peak onto other hours, hours which may be those of the system peak (Attorney General Brief, p. 143).

The Company maintains that demand charges are necessary. Although demand charges are based upon customers' maximum demands instead of their demand at time of system peak, the Company argues that the correlation between the two is high enough that the method is effective. Additionally, the Company states, without a demand charge there would be no incentive for customers to reduce peak use at the most critical times to the system, which would increase system costs and thus costs to ratepayers (Company Brief, pp. 268-269, 274-276).

The Consortium argues that the evidence clearly indicates that the removal of demand charges would send the wrong cost

signals to customers. According to the Consortium, elimination of demand charges would tell customers that their consumption patterns within the peak period are of no consequence. The Consortium states that this is wrong and thus the Attorney General's request should be rejected here as it was in Fitchburg Gas and Electric Light Company, D.P.U. 84-145-A (1985) (Consortium Brief, p. 4).

The Company, through its witness, recognizes that KWH rates with hourly time periods would provide customers with the incentives the Attorney General describes (Tr. 18, pp. 2229-2231). Presently, though, for administrative and institutional reasons, such rates have not been offered on a large scale. With the broad peak period the Company has, KWH rates would only encourage customers to install equipment with larger capacities which ran at least as efficiently on an energy basis as equipment appropriately sized.

That equipment would be larger in order to have the capability to meet worst-case scenarios. For example, if there were no demand charge, there would be no incentive to limit demand on a peak day. If the added cost of a larger air conditioner were less than the cost of insulation (as well might be the case, assuming, for instance, that larger units tend to be more energy-efficient throughout their range), it would be cheaper for the customer to purchase the larger air conditioner rather than insulate to meet peak cooling day requirements. This could actually reduce the conservation and load management

engaged in by large customers when it is most needed by the utility system. While, as the Attorney General contends and the Company concedes, the signal from demand charges is not perfect, we find it is still better than the signal which would be given through KWH charges spread over the number of peak hours which this Company has. Therefore, until such time as hourly KWH billings become administratively and institutionally feasible, we reject the elimination of demand charges. See also, Fitchburg Gas and Electric Light Company, D.P.U. 84-145-A (1984).

C. Specific Rates

1. Rates R-1 and R-3, Regular Residential and Residential Space Heating

Rate R-1 is the Company's general residential rate. As a result of the proposed elimination of certain of its other rates, the Company proposes to allow other types of customers to be served under this rate as well. The Company's proposed availability clause reads:

> Available for lighting, heating and other uses in residential premises, for service in an edifice set apart exclusively for public worship, condominium common areas (per M.G.L. Chapter 164 Section 94H), and cooperative common areas (per DPU 1720) excluding hotels, apartment buildings of ten or more dwelling units where the bills are not rendered by the Company directly to the individual tenants. Not available for Auxiliary Service (Exh. BE-302).

Additionally, during the proceedings in this case the Company proposed to combine Rate R-3 with Rate R-1. It argues that both the marginal costs and embedded costs of the rates are so similar that two separate rate classes are not justified

(Exh. BE-200S). Rate R-3 is the Company's residential electric rate for residential premises, condominium common areas, and cooperative apartment common areas which have total electric water and space heating requirements.

In its design for the combined Rate R-1/R-3 in this case the Company developed the rates in the general manner described above. It also followed the Department's Order in D.P.U. 1720 regarding the gradual elimination of summer surcharge blocks within the rates. In that Order we stated that for Rate R-1 (then B):

> The Company shall propose to apply the summer surcharge to all KWH for regular customers in its next rate case. For water heating customers, in its next case the Company shall apply one-half of the summer surcharge to the first 350 KWH, and the full summer surcharge to all KWH over 350. In its second rate case following this one the Company shall apply the summer surcharge to all KWH for water heating customers. Id., p. 181.

Similarly, for Rate R-3 (then B-3) customers, the Department ordered that:

> In the next rate case, the Company shall propose for this rate class a rate in which the full summer surcharge applies to all KWH over 350 and one-half the summer surcharge applies to all KWH under 350. In its second rate case following this one the Company shall apply the summer surcharge to all KWH for Rate B-3 customers. Id., pp. 179-180.

No party objected to either the rate design proposed by the Company for the residential rates in this case, or the combining of Rates R-1 and R-3.

Based on our review of the bill impacts, given the revenue requirement determined in this Order and the marginal costs

calculated in this Order, we find that rates based on marginal costs do not violate the Department's goal of continuity in this case. Further, we find that continuity is not violated if water heating customers are charged the full marginal-cost-based rate for all of their consumption in the summer. Therefore, we find the elimination of the 350 KWH energy block in the summer for these customers to be appropriate.

Based on our review of the marginal costs and embedded costs of serving Rates R-1 and R-3, we find that, indeed, the Company's contention that the embedded and marginal costs of the two rates are similar is correct. Therefore, we will allow the Company to combine the two classes into one class. We are concerned, however, that these costs may diverge more significantly in the future based on changes in the Company's marginal costs. Therefore, we order the Company to maintain Rate R-3 customers as a separate subcode of Rate R-1 and to analyze and report, in its next general rate proceeding, whether the embedded and marginal costs to serve subcode R-3 customers and the remainder of Rate R-1 customers remain similar.

Based on these findings, then, we find that the appropriate seasonal energy charges are those shown in Schedule 15. The appropriate customer charge shall be calculated so as to be the same in all months and to meet the remainder of the rate's allocated revenue requirement.

Finally, in conformance with the findings below regarding auxiliary service rates, we require the Company to remove the

auxiliary service restriction from the availability clause for this rate.

2. Rate R-2, SSI Rate

Rate R-2 is the Company's residential rate which provides a discount from its regular residential rate for certain qualified customers. The customers served under this rate must (1) be the head of a household or principal wage earner, and (2) be presently receiving Supplemental Security Income from the Social Security Administration.

Consistent with the Department's Order in D.P.U. 1720 which first allowed this rate, the Company has discounted the customer charge and base energy charge for the first 350 KWH by 40 percent. The revenue shortfall which results from this discount is allocated to all other rate classes in proportion to their share of rate base so that the other classes provide equal rates of return.

No party objected to the Company's proposal.

The Company's proposal is reasonable and continues the discount in the same manner as allowed by the Department in D.P.U. 1720. We find the continued 40 percent discount from the monthly customer charge and first 350 KWH of the energy charge to be appropriate. Based on these findings, then, we find that the appropriate seasonal energy charges are those shown in Schedule 15. The appropriate customer charge shall be calculated so as to be 40 percent of the customer charge for Rate R-1.

3. <u>Rate R-4, Optional Residential TOU Rate</u>

Rate R-4 is the Company's optional time-of-use ("TOU") rate for residential customers. As ordered in D.P.U. 1720, the requirement for controlled water heating has been removed from the rate. The Company designed the rate in accordance with its calculation of marginal costs, and added to the customer charge the amount required to reflect the additional cost of a TOU meter (Exh. BE-300, p. 21; Exh. BE-325, pp. 95-99). No party objected to the Company's proposed rate design.

We find the Company's method to be in conformance with prior Department Orders. Therefore, we find that Rate R-4 should be calculated using the Company's method and the marginal costs found by the Department in this case. Based on these findings, then, we find that the appropriate seasonal energy charges are those shown in Schedule 15. The appropriate customer charge shall be calculated the Rate R-1 customer charge plus the additional monthly cost of the TOU meter.

Finally, in conformance with the findings below regarding auxiliary service rates, we require the Company to remove the auxiliary service restriction from the availability clause for this rate.

4. <u>Rate R-5, Optional Residential TOU Rate</u>

Rate R-5 was the Company's optional TOU rate for residential service. In D.P.U. 1720 the Department ordered the availability of this rate closed and the customers transferred, in the Company's next rate case, to a TOU rate which more appropriately

indicates the Company's cost. Id., p. 183. In this case the Company has filed Rate R-4 as its TOU rate. It proposes to eliminate Rate R-5 as ordered in D.P.U. 1720 and to transfer Rate R-5 customers to Rate R-4. It states that all Rate R-5 customers receive lower bills under proposed Rate R-4 than under Rate R-5 (Exh. BE-300, p. 21; Exh. BE-317). No party objected to the Company's proposal.

Based on the evidence in this case, we find that the Company has complied with the Department's Order in D.P.U. 1720. We also find that under the Company's proposed Rate R-4 all Rate R-5 customers receive lower bills. Further, we find that, even with the changes to Rate R-4 required because of the revision to marginal costs found to be necessary in this case, the transfer of Rate R-5 customers to Rate R-4 will not violate the goal of continuity. Therefore, we find that Rate R-5 shall be eliminated and its customers transferred to Rate R-4.

5. Rate R-6, Residential Water Heating

Rate R-6 is the residential water heating rate. Some of the customers on this rate have timers to control their use of water heating and some have uncontrolled service. In this case the Company proposes to eliminate the rate and combine the customers' water heating use with their use under Rate R-1. The treatment of the water heating rate was the subject of a separate proceeding in D.P.U. 84-194, where the Department found that the rate should be eliminated. In that case the Department also found that the Company should file interruptible rates

which are available to all of its customers and that the availability of such rates would meet the needs of residential water heating customers who wish to heat their water off-peak. D.P.U. 84-194, pp. 9-11.

Robinson alleges that the L-700 customers have not been notifed formally or informally of possible rate consolidation into the R-1 customer rate class (Robinson Brief, p. 3). He argues that Rate R-6 customers should be offered an interruptible rate (Robinson Brief, p. 5).

The Company argues that its proposal to eliminate Rate R-6 is consistent with its D.P.U. 84-194 compliance filing of October 11, 1985. Additionally, it states that it has a plan to notify customers of the consolidation, contrary to what Robinson alleges. Finally, the Company argues that it has not proposed an interruptible rate for R-6 customers because it is just instituting its interruptible rates, and the administrative complexity of providing interruptible rates for secondary customers would involve logistics which would overwhelm the pricing calculations which the Company believes constitute the key concept in the Department's Order in D.P.U. 84-194 (Company Brief, pp. 293-295).

The questions here are simple: has the Company notified or does it have plans to notify the Rate R-6 customers of the options available to them, and should the Company offer them an interruptible rate.

The Company does have a plan to notify Rate R-6 customers of

their options (Exh. HO-43). Further, the Company has agreed that it is possible to notify these customers that they can have the timer of their water heater clock disabled so that they can receive continuous service, inasmuch as the timers are not set in an appropriate manner (Tr. 22, pp. 2955-2956). Boston Edison Company, D.P.U. 84-194, pp. 5-6) (1985).

The Company has not filed an interruptible tariff which is available to all of its customers. Whether the Company should file a tariff available to Rate R-6 customers is discussed in the interruptible rate section, below.

Based on our Order in D.P.U. 84-194 and the evidence in this case, we find the Company's plan to eliminate Rate R-6 acceptable, subject to the notification procedure described above. The proposed notice, as well as any other proposed notices which result from this Order, must be filed with the Department for reviews by its Consumer Division in advance of their issuance by the Company.

6. Rate G-1, Small General Service

Rate G-1 is the Company's small general service rate. The proposed availability clause reads: "Available for all use at a single location where the monthly demand is less than 10 kilowatts. Not available for resale." The present Rate G-1 consists of a customer charge, a two-block energy charge which is differentiated by season, and a demand charge, differentiated by season, for all demand in excess of 10 KW. The maximum demand allowed on the present rate is 20 KW.

The Company proposes to have only one energy block whose price is differentiated by season, and to limit the availability of the rate to customers whose demand is below 10 KW. As a result of this latter change, the Company proposes to eliminate the demand charge on this rate since it has applied, in the past, only to demand in excess of 10 KW. The Company argues that it is not cost-effective to meter demand below 10 KW (Exh. BE-300, pp. 16-17). The Company calculated the charges for this rate in the general manner described above. No party objected to the Company's proposal for this rate.

The Company has reflected, in its proposed design for this rate, the appropriate seasonal differentials. As noted above, however, the change in the revenue requirement allowed by the Department and in the marginal costs found to be appropriate enables the Department to move closer to marginal-cost-based rates than the Company's proposal. If rates for this class were set at full marginal cost, the customer charge would be negative. As we noted, the record does not include any evidence regarding how this situation should be addressed. The best course, we believe, is to set the customer charge at zero and to meet the class revenue requirement through the energy charges. According to the Company's witness Saunders, the energy charges should retain the same ratio between seasons as the marginal-cost-based energy rates (Tr. 22, pp. 2942-2944). We will accept, for this case, the Company's preference for constant ratios. We note, however, that the cost/benefit

analysis used to determine an investment in C&LM or the decision to consume more energy during peak versus off-peak is driven not by the ratios but by the absolute dollar difference between the rates themselves. Therefore, we instruct the Company to address this issue in its next case. Additionally, we find the Company's proposal to eliminate the demand charge for this rate appropriate given that it is not cost-effective to meter customers whose demand is below 10 KW. Based on these findings, then, we find that the appropriate seasonal energy charges must meet the class revenue requirement while maintaining the ratio between seasonal marginal costs. The rates should approximate those shown in Schedule 15. The appropriate customer charge is zero.

7. Rate G-2, Medium and Large General Service at Voltage Levels Below 13.8 KV

Rate G-2 is the Company's general service rate for customers served at the secondary and primary voltage levels whose demands exceed 20 KW. The present rate includes a customer charge, seasonally differentiated demand charges, and two-block energy charges based on hours' use where the second block is seasonally differentiated.[25/]

25/ Hours' use energy charges are proxies for TOU rates. A customer's hours' use is calculated by dividing his KWH bill by his KW demand. If there are, for example, 200 peak hours' in a month, it is a mathmatical fact that all energy use of customer in excess of 200 hours must take place in off-peak hours. Thus, the Company could send the correct price signal by having the first 200 hours' use at marginal energy cost during peak hours and all use in excess of 200 hours at the off-peak marginal cost.

The proposed availability clause for the rate reads: "Available for all use at a single location where the service voltage is less than 5000 volts and the monthly demand is equal to or greater than 10 kilowatts. Rate T-2 must be used by customers whose usage characteristics would normally be served under Rate G-2 if they are required to have a time of use rate by the DPU." As noted above, the Company proposes to move all present Rate G-1 customers whose demands are equal to or in excess of 10 KW to Rate G-2. Additionally, it proposes to maintain the hours' use format, but to reduce the hours' use step from 300 hours' use to 180 hours' use. The Company contends that a step at 180 hours' use more closely approximates the rate's average hours' use at peak. The seasonal differentials in both blocks of the energy charges and in the demand charges are, according to the Company, set at the appropriate marginal cost levels, using its general method of determining rate design discussed above.

The Company has also proposed, based on its cost/benefit study of TOU rates ordered by the Department in D.P.U. 1720, to transfer its 266 largest customers to Rate T-2, the TOU rate for Rate G-2. It further plans to reevaluate the remaining customers on Rate G-2 to determine whether the transfer of more customers is cost-effective. The Company states that it can install 150 to 200 TOU meters annually with its existing manpower. If the Company's reevaluation shows that it is still cost-effective to transfer customers to Rate T-2, the Company

will transfer 75. It will continue this process every six months until such time as the transfer of customers no longer proves to be cost-effective (Exh. BE-316).

In an effort to consolidate its rates, the Company also proposes to establish an interim rate, Rate G-2A. It states that Rate G-2A has the same design characteristics as Rate G-2 (customer charge, seasonally differentiated demand and energy charges, and one hours' use block). The differences between Rate G-2 and G-2A are that (1) the hours' use step is at 140 hours' use, which approximates the average hours' use at peak for the transferred customers, instead of at 180 hours' use;(2) the demand charge in each season is lower (the energy and customer charges are the same); and (3) those customers transferred from Rate G-8 who presently have a controlled off-peak provision on their rate would be allowed to maintain it.

The reason for the establishment of Rate G-2A is that the Company claims that a direct transfer to Rate G-2 for these customers would violate continuity. BECo also notes that many of the rates which would be combined into Rate G-2A are end-use or special rates (Tr. 22, pp. 2944-2948). For example, most subcodes of Rate G-8, the end-use rate for space heating and cooling, are proposed for transfer to Rate G-2A. The customers under this rate already take their other electrical demands under Rate G-2. The Company states that many customers will find it advantageous to combine their demands under Rate G-2

because of the diversity within a customer's own load. Over time, then, the Company expects that many of the customers on proposed Rate G-2A will voluntarily move their load to Rate G-2 (Tr. 22, pp. 2944-2947).

The Company proposes to transfer the following rate subcodes to Rate G-2A: Rate G-6, all secondary customers and primary customers without transformer ownership (Exh. BE-311); Rate G-7, subcode 130 for accounts with more than nine apartments per meter, subcode 234 (Exh. BE-312); Rate G-8, subcodes 091, 093, 593, 599 (Exh. BE-313); and Rate G-9, subcode 430.

No party objected to the Company's proposed design for this rate. The Consortium objected to the increase in power factor provision for this rate without a corresponding adjustment to the billing units used to calculate the rates. Our discussion of the Consortium's contentions is addressed under Rate G-3 since it is there that the impact of the analysis of the issue is most significant. Based on our finding there, no adjustment to the billing units used to calculate the rate for the increased power factor provision is necessary for Rate G-2.

We appreciate the Company's move to consolidate rates in accordance with the Department's Orders. There are several aspects of the Company's proposal, however, which require modification. First, in designing its rates, the Company imposed a 10 KW minimum demand for Rates G-2 and G-2A. It would require that, if a customer has a demand greater than or equal to 10 KW, he take service under Rate G-2. Further, however, the

Company would set 10 KW as the minimum billing demand under the rate. Thus, for example, if a customer had one month at 12 KW and all the other months at 8 KW, he would still be required to pay a demand charge calculated using 10 KW in the months with only 8 KW demand. This is, quite simply, a demand ratchet. The Department has rejected the use of demand ratchets in several cases (Western Massachusetts Electric Company, D.P.U. 84-25 (1984); Fitchburg Gas and Electric Light Company, D.P.U. 84-145-A. (1984)). We similarly reject them here. While the requirement that a monthly demand in any of the last 12 months in excess of 10 KW place the customer on Rate G-2 is appropriate, the minimum monthly demand is not. Indeed, such a minimum demand exacerbates the interface between Rates G-1 and G-2. Therefore, we find that the billing demand in any month under Rate G-2 shall be the actual metered demand. The provision for determining whether demand has exceeded 10 KW in the most recent 12 months, and the requirements for service under Rate G-2, may remain.

Second, similar to the results for Rate G-1, a negative customer charge results from use of the revised marginal costs, given the revenue requirement allowed by the Department. As with Rate G-1, we find that the record is devoid of the appropriate treatment for this situation and that a customer charge of zero results in the least disruption. Further, based on our review of the bill impacts, we find that a rate design where the customer charge is set at zero, the energy charges are

moved to full marginal cost, and the demand charges are designed to meet the rest of the rate revenue requirement such that the ratio between seasonal marginal demand costs is maintained, results in rates which do not violate continuity. As the Company maintains, we find that where TOU rates are not justified on a cost/benefit basis, hours' use rates serve as the best proxy for TOU rates.

Third, rates may be calculated using this rate design utilizing combined billing determinants for Rates G-2 and G-2A. These billing determinants result in a new hours' use block at 175 hours (Exh. HO-RR-58). Using these combined billing determinants and the rate design described above, we find, based on our review of the bill impacts, that continuity is not violated if classes are transferred to the combined Rate G-2/G-2A instead of a specially designed Rate G-2A. The controlled off-peak provision for transferred G-8 customers which was included in Rate G-2A will be allowed for Rate G-2, but with its availability closed as proposed by the Company. The Company must also provide a plan for the elimination of the provision in its next rate case.

Based on these findings, then, we find that the appropriate seasonal energy charges are those shown in Schedule 15. The appropriate customer charge is zero. The appropriate seasonal demand charges should be calculated so as to meet the remainder of the class revenue requirement, while maintaining the ratio of seasonal marginal costs. The charges should approximate those

shown on Schedule 15.

The Company has proposed to transfer 266 of its largest customers to Rate T-2 on a mandatory basis. It further proposes to reevaluate the continued transfer of additional customers. In response to questioning by the Bench, the Company's witness responded that the largest customers on Rate G-2 would be the ones for whom it would be most cost-effective, in terms of the system, to be transferred to Rate T-2. In response to Bench Record Request 34, the Company provided a revised availability clause for Rate G-2 which explicitly stated that customers with demands in excess of 150 kw would be transferred in order of size, with the largest first, at a rate of 150 customers per year. Since this clause more accurately describes that method, we find that it must be part of the availability clause used in the Company's compliance filing for this case.

8. <u>Rate G-3, Large General Service at 13.8 KV</u>

Rate G-3 is the Company's general service rate for customers who take their service at the 13.8 KV (high-tension) voltage level. This service is available only in certain locations within the Company's service territory where such service voltages exist. As a result of the Department's Order in D.P.U. 1720, this rate is a mandatory TOU rate. The rate consists of an initial demand block of 150 KW, and an additional, seasonally differentiated demand charge for all additional KW of demand, and energy charges which are differentiated by time periods within a day and by season.

The present availability clause, which remains unchanged in the Company's proposed rate, reads:

> Available for all use at a single location on contiguous private property if service is supplied to the customer and metered at 14,000 volts nominal and if the customer furnishes, installs, owns and maintains at his expense all protective devices, transformers and other equipment required by the company. Not available for resale.

The Company's proposed rate for this class maintains the present format. It moves one-third of the way between existing rates and full marginal-cost-based rates for both the demand and energy charges, with the remainder of the allocated revenue requirement met by the customer charge. No party objected to the Company's proposed rate design. The Consortium, however, contested the Company's calculation of the increase in demand billing units which it would experience as a result of the increase in its power factor provision.

The Company bills most general service customers under rates which contain an 80 percent power factor provision. Power factor is the the ratio of KW to kilovolt-amperes ("KVA"). It is important because utilities must size their generation facilities so as to meet KVA loads. The load in terms of KVA is higher than the KW measured at a meter. The power factor provision states that the billing demand in the rates will be the higher of a customer's measured KW or 80 percent of the measured KVA. In this case the Company proposes to increase the power factor provision from 80 percent to 90 percent. Its ultimate goal is to require a 100 percent power factor, i.e., KVA billing (Company Brief, pp. 270-271; Exh. BE-300, p. 26).

Since KVA demand is generally higher than KW demand, any increase in power factor requirements by the Company will increase the billing units it has in a given period. The Company calculated what the increase in billing units would be for Rate G-3. It then reduced this amount by 55 percent based on the assumption that 55 percent of the possible billing unit increase caused by the increased power factor provision would be eliminated by customers correcting their power factor on their own. The Company maintains that its 55 percent reduction to the adjustment is reasonable since it is very cost-effective for customers to correct their power factor (paybacks of less than one year). It also proposes to apply the increased power factor requirement to Rate G-2, but has made no adjustment to billing units or revenues since it believes most G-2 customers already exceed the 90 percent power factor. (Company Brief, p. 273; Exh. BE-305, p. 5).

The Consortium argues that the 55 percent reduction to the power factor adjustment should not be allowed since it is not known and measurable (Consortium Brief, pp. 5, 17-18). Further, it states that the Company has made no adjustment to Rate G-2 billing units for the change in power factor and that, as a result, the Company could receive a "windfall" of as much as $7 million. It concludes that the Department should thus disallow the change in power factor for Rate G-2 or require adjustment to Rate G-2 billing units in the Company's compliance filing (Consortium Brief, pp. 19-20).

The Company argues that the Department should allow it to increase power factor requirements and should allow the 55 percent reduction to the calculated increase in billing units. If the 55 percent adjustment is not allowed, the Company asserts, then any adjustments customers do make will result in revenue loss to the Company (Company Brief, p. 273). Further, it maintains that, since payback for installation of power correcting equipment is so short, 55 percent is a reasonable estimate of correction. It also argues that, since there is consultant support available in the market to assist with the installation of correction equipment and the Company will also assist customers, the 55 percent reduction to the adjustment is reasonable.

The Company also contends that its proposed reduction to the billing unit adjustment is supported by precedent. It maintains that adjustments like this have been made before to billing units, as in the law requiring a change in how common areas in condominiums were billed. It also argues that it is not making an adjustment to billing units for forecast sales increases, as the Consortium contends. Rather, the Company states, the customers' reaction to increased power factor requirements is a specific, well-defined change for which adjustment is appropriate. If the Department does not allow the Company's 55 percent adjustment, the Company concludes, the whole proposal to increase power factor requirements should be discarded (Company Brief, pp. 270-273).

The Department has previously found that KVA billing best reflects the costs that a company incurs (Cambridge Electric Light Company, D.P.U. 84-165-A (1985); Massachusetts Electric Company, D.P.U. 85-146 (1986)). The Company's proposal to increase power factor in this case is consistent with movement to complete KVA billing. While there may, indeed, be some customer response to the increased power factor requirements so that customers reduce their billing demands, there is absolutely no support on this record for the figure used by the Company of 55 percent. Further, the Company's past record for estimating these types of adjustments has not been good. For example, in D.P.U. 1720 the Company estimated participation in its proposed SSI rate at 100 percent of eligible customers. The Department allowed an adjustment based on 30 percent participation based on the experience of other companies. The actual participation rate was even lower, as shown by the adjustment for SSI revenues proposed by the Company in this case. For these reasons we find that the Company shall increase its power factor requirements for Rates G-2 and G-3 to 90 percent, without the proposed reduction of 55 percent. These adjustments increase test year billing demands by 7.375 percent in the summer and by 6.566 in the winter.

The change in power factor for Rate G-2 will also have some effect on billing units. Since G-2 loads are less subject to the need for power factor corrections (light and heat) and since there will be some unquantified revenue loss in G-3, we will

increase the G-2 power factor requirements without billing unit adjustment as a counter-balance to the change in Rate G-3.

In addition to the issue raised by the Consortium, the changes in the marginal costs determined by the Department and the revenue requirement allowed by the Department have an effect on the Company's proposed rate design. If rates for Rate G-3 were set at full marginal cost with the remainder of the class revenue requirement collected through the customer charge, the resulting customer charge would be so large that the bill impacts would violate continuity for smaller customers. The major cause of this is the large decrease in the energy charge for this rate if marginal costs are used. In attempting to determine the extent to which rates could be moved toward marginal costs, the Department evaluated a variety of alternatives. The one which allowed the greatest movement toward marginal costs while maintaining continuity was developed by maintaining a consistency between the general service rates.

First, as with Rate G-2, the Company has a monthly minimum billing demand. In this case it is 150 KW. As discussed above, this is no less than a billing ratchet, which the Department has rejected many times in the past. Therefore, based on the same analysis which led us to reject the minimum billing demand for Rate G-2, we reject the minimum billing demand for Rate G-3. Second, Rates G-1 and G-2 have zero customer charges. Most of the undesirable bill impacts in Rate G-3 result from the large customer charge necessary to reconcile the Company's proposed

rate design with the allocated revenue requirement. If the customer charge is set at zero as for Rates G-1 and G-2 and the seasonal demand charges are set at full marginal cost, the effect of the large customer charge on small customers can be eliminated while retaining the valuable demand signal that marginal costs provide. This requires that the remaining portion of the allocated revenue requirement be met through the energy charges. Since the present energy charges are in excess of marginal costs and since the Department is unable to set them at marginal cost for continuity reasons, it is appropriate to move the energy charges as close to marginal cost as possible. As the Company has indicated, it believes that the ratios between the time periods for marginal energy costs should be maintained even if the rates themselves are not set at marginal cost. Thus, the Department solved for the summer peak energy charge which, when coupled with the summer off-peak, winter peak, and winter off-peak energy charges so as to maintain the same ratios as the marginal energy costs, met the design revenue requirement. The resulting summer peak energy change results in a movement of approximately 50 percent of the way toward marginal cost from existing peak rates, and 80 percent for off-peak rates. Based on our review of the bill impacts produced by these rates, we find that they do not violate the goal of continuity.

Based on these findings, then, we find that the appropriate seasonal demand charges are those shown in Schedule 15. The appropriate customer charge is zero. The appropriate energy

charges are those calculated as described above and should approximate those shown in Schedule 15.

9. Rate G-5, Church Rate

Rate G-5 is the Company's rate which is "Available for lighting, heating and incidental power service in an edifice set apart exclusively for public worship." The Company proposes to eliminate this rate in this case. The Company states that, based on its analysis, Rate G-5 customers should be transferred to Rate R-1 since their customer load factors and coincident peak load factors are most similar to those of Rate R-1 (Exh. BE-300, p. 18). No party objected to the Company's proposal.

Based on the evidence in this case, and our analysis which indicates that the bill impacts from the transfer do not violate our goal of rate continuity, we find the Company's proposal to eliminate this rate and transfer its customers to Rate R-1 acceptable.

10. Rate G-6, All-Electric Church and School Rate

Rate G-6 is the the Company's rate which is

> Available for service in public and private school buildings and edifices set apart exclusively for public worship if the entire energy requirements are electric, and are supplied at one metering point, and if the electric space heating, water heating and cooking equipment installations are acceptable to the Company. This rate is not available for Auxiliary Service, nor for temporary, periodic or seasonal service.

The Company proposes to eliminate this rate in this case and transfer its customers to Rates G-2A and G-3. No party objected to the transfer of Rate G-6 customers to Rate G-2A. Bentley, which is presently served under Rate G-6 and would be

transferred to Rate G-3, objected to the elimination of this rate and its proposed transfer.

In D.P.U. 1720 the Department directed the Company to justify the continued availability of Rate G-6. After examination of the issue, the Company concluded that Rate G-6 should be eliminated and rate revenue subcodes 112 and 113 of Rate G-6 should be transferred to Rate G-2A, and rate revenue subcode 114 should be transferred to Rate G-3 (Exh. BE-300, p. 18). According to the Company, these conclusions were dictated by a review of metering and use characteristics (Exh. BC-1).

Bentley argues that Rate G-6, subcode 114 should not be consolidated with Rate G-3. It states that such consolidation would violate continuity because base rates would increase by 37 percent (Bentley Brief, p. 2). It maintains that the Company has not provided reasonable notice of this proposed change to its affected customers (id., pp. 4-6). The Company's proposal also violates fairness considerations, according to Bentley, because the cost of serving Rate G-3 customers has not been shown to be the same as those of serving Rate G-6, subcode 114 customers (id., pp. 6-10). Therefore, Bentley concludes that the five Rate G-6, subcode 114 customers should be put on an interim rate until the Company demonstrates that they belong on Rate G-3 (id., pp. 11-14).

The Company maintains that the 114 subcode of Rate G-6 should be consolidated with Rate G-3. If G-6 is not eliminated, the Company states, it will face a base rate increase of 100

percent to meet its equalized return revenue requirement. Further, according to the Company, the decrease in fuel cost and thus ratepayers costs makes this an especially propitious time to consolidate the rates. The Company argues that, even with the base rate increase, Bentley's total bill will be lower than it was in the test year, and that the total bill is the appropriate measure of continuity. Finally, the Company states that if the Department finds that some adjustment is appropriate, the Company will not object, but that the basis of that adjustment should not be the adjustment proposed by Bentley, which would actually decrease Bentley's rates and exacerbate the present situation (Company Brief, pp. 279-284).

To determine whether the Company's proposal violates continuity, the Department must determine the appropriate measure of continuity. Clearly, customers respond not to the level of their base rates, but to the size of their total bill. Thus, the appropriate measure of continuity is the change in the total bill. Bentley also references the percentage increase it faces as being greater than the general rate increase requested by the Company by seven times. The percentage increases faced by customers as compared to the increases sought by the Company are not the issue; the Department has continually found that rate classes should be charged rates which meet the cost of serving them. The issue is whether the size of the increase, in and of itself, violates continuity.

Bentley also argues that the Company has not provided its

customers with sufficient notice and has, in fact, "unconscionably concealed its intent" to change the rate (Bentley Brief, p. 6). Bentley would hold the Company to a standard of notification that is unreasonable. Bentley was on notice as a result of the Department's Order in D.P.U. 1720 that major changes were in the offing for Rate G-6. When Bentley did contact the Company to inquire about the rate, it was told that the Company was proposing to abolish it. It is unreasonable to expect the Company actively to notify its customers about every rate change it proposes before that proposal is approved by the Department. The Company notified its customers that it had filed for a general rate increase, and Bentley certainly became aware of the impact of the proposal on it as evidence by its active intervention in this proceeding. We therefore reject Bentley's agreement regarding lack of notice.

Bentley also argues that the Company's proposal violates the fairness criterion because it has not been shown that it costs the same to serve Rate G-6, subcode 114 customers as it does to serve Rate G-3 customers. But this is not the appropriate analysis. First, the question is whether Bentley meets the requirements for service under Rate G-3. The requirements for Rate G-3 are clear: a customer must have a demand of 150 KW and be served at 13.8 KV. Bentley meets these requirements. Once it is determined that this is the appropriate rate to transfer Bentley to, the question arises as to whether Bentley is different from other customers on this rate. As the Company

notes, Bentley posits that it is different because the costs to serve the customers on Rate G-6 are different based on comparisons of average coincidence factors of the two rates. Average coincidence factors do little to explain whether the customers in Rate G-6, subcode 114 fit within the established profile of Rate G-3 customers. As we find below with regard to auxiliary service charges, it is not the average which is important, but the extremes, in determining whether a customer can be served on a particular rate. Therefore, we find that Bentley's contention is unsupported.

The issue on which we base our decision, then, is continuity. There are actually two total bills which could be examined. The Company argues that the test year total bill should be compared to the proposed total bill, a comparison which would reflect the decrease in fuel prices. The other alternative is to examine the total bills using a constant fuel charge. We have examined both alternatives for computing changes in total bills for the Rate G-6, subcode 114 customers as a whole and for Bentley in particular, given the rates developed for Rate G-3 in this Order. We find that these comparisons indicate that continuity is not violated in either case. Further, we note that the lowest energy charge available under base rates for Rate G-6 was $.05441 per KWH. The off-peak rate for Rate G-3 as a result of this Order is almost five cents per KWH lower than that, which offers tremendous opportunities for off-peak heating.

Therefore, we find that the Company may eliminate Rate G-6 as it has proposed. The customers it proposed to transfer to Rate G-2A shall be transferred to Rate G-2. The customers it proposed to transfer to Rate G-3 shall be transferred to that rate.

11. Rate G-7, All-Electric Apartment House Rate

Rate G-7 is one of the Company's special apartment house rates. It is available

> only to customers on Rate C-1 as of March 10, 1978 subject of any exemption required by State or Federal law, for domestic service and building use in apartment houses having four or more dwelling units (not including apartment hotels) when the entire energy requirements, including that for the individual apartments, are electric and are supplied at one metering point and are not submetered or otherwise measured for resale, and if the electric space heating, water heating and cooking equipment installations are acceptable to the Company. Service will not be supplied hereunder for general commercial use in stores, shops, offices, garages or restaurants, but such service will be separately metered and provided under the Company's appropriate filed rates. This rate is not available for Auxiliary Service, nor for temporary, periodic or seasonal service.

In this case the Company proposes to cancel this rate and transfer its customers to other rates based upon their load characteristics. Sub-code 130 consists of apartment houses which range in size from four apartments per meter to 320 apartments per meter. For this subcode, the Company proposes to transfer accounts with less than ten apartments per meter to Rate R-3. This group comprises approximately 56 accounts. The Company proposes to transfer the remainder of the subcode the Company proposes to transfer to Rate G-2A. Sub-code 234 consists of ten customers which have primary metering (i.e., at

a voltage level greater than 400 volts). The Company proposes to transfer these customers to Rate G-2A. Subcode 334 consists of one customer which is served at the 13.8 KV voltage level. The Company proposes to transfer this customer to Rate G-3 (Exh. BE-300, p. 19; Exh. BE-312). No party objected to the Company's proposal.

Based on the evidence in this record, and our analysis of bill impacts which indicates that the goal of continuity will not be violated as a result of the transfer, we find the Company's proposal to eliminate this rate acceptable. All customers which it proposes to transfer to Rate R-3 shall be transferred to Rate R-1 since these rates have been combined as requested by the Company. All customers which the Company proposes to transfer to Rate G-2A shall be transferred to Rate G-2 since this Order combines those two rates. The customer which the Company proposes to transfer to Rate G-3 shall be so transferred.

12. <u>Rate G-8, Space Heating</u>

Rate G-8 is the Company's rate which is available:

> only to customers on Rate J or having a building permit as of September 1, 1984 for space heating, water heating and air conditioning service only if the entire heating requirements of the area servced hereunder are supplied by electricity and if the heating and cooling equipment (including installation) are acceptable to the Company, and if all other service supplied to the premises is separately metered and provided under the Company's appropriate filed rate. This rate is not available for heating supplementary to that provided by other means nor for Auxiliary Service nor for temporary, periodic or seasonal service.

In this case the Company proposes to cancel this rate and

transfer its customers to other rates based on their load characteristics. Subcode 091 of this rate serves approximately 600 apartment house customers. The Company proposes to transfer these customers to Rate G-2A. Subcode 092 serves approximately 170 small apartment houses and individual customers. The Company proposes to transfer these customers to Rate R-3. Sub-code 093 serves approximately 2,500 customers in commercial office buildings. The Company proposes to transfer these customers to Rate G-2A and to provide, upon request, the results of a combined billing under Rate G-2 of the customers' G-2 and G-2A loads. Because a particular customer may have diversity between these loads, a combined billing may reduce his bill. Subcode 593 serves eight commercial customers under the off-peak thermal storage provisions of the rate. The Company proposes to transfer these customers to Rate G-2A. Subcode 599 serves approximately 44 apartment house customers under the off-peak thermal storage provisions of this rate. The Company proposes to transfer these customers to Rate G-2A (Exh. BE-300, p. 19; Exh. BE-313). No party objected to the Company's proposal.

Based on the evidence in this record, and our analysis of bill impacts which indicates that the goal of continuity will not be violated as a result of the transfer, we find the Company's proposal to eliminate this rate acceptable. All customers which it proposes to transfer to Rate R-3 shall be transferred to Rate R-1 since these rates have been combined as requested by the Company. All customers which the Company

proposes to transfer to Rate G-2A shall be transferred to Rate G-2 since this Order combines those two rates.

13. Rate G-9, Apartment House Rate

Rate G-9 is another of the Company's special apartment house rates. It is available

> only to customers on Rate K as of March 10, 1978 subject to any exemptions required by State or Federal law, for domestic service and incidental building use in apartment houses having ten or more dwelling units if the entire service, including that for the individual apartments, is supplied at one metering point and is not submetered or otherwise measured for resale. Electricity will not be supplied under this rate for use of others than the customer and the tenants. Not available for Auxiliary Service.

In this case the Company proposes to cancel this rate and transfer its customers to other rates based upon their load characteristics. Subcode 430 of the rate consists of apartment houses with 10 to 350 dwelling units per meter. The Company proposes to transfer these customers to Rate G-2A. Subcode 435 consists of two customers served under special experimental contracts for off-peak electric heat storage. The Company proposes to transfer these customers to Rate T-2 (Exh. BE-300, pp. 19-20; Exh. BE-314). No party objected to the Company's proposal.

Based on the evidence in this record, and our analysis of bill impacts which indicates that the goal of continuity will not be violated as a result of the transfe, we find the Company's proposal to eliminate this rate acceptable. All customers which the Company proposes to transfer to Rate G-2A shall be transferred to Rate G-2 since this Order combines those

two rates. The customers which it proposes to transfer to Rate T-2 may be so transferred.

14. Rate G-10, Miscellaneous Energy Rate

The Company's Rate G-10 is "available only to customers on Rate H prior to April 30, 1982. Pursuant to the Order in DPU 1720 dated June 29, 1984, remaining customers on this rate will be transferred to Rate G-1 or another applicable rate and this rate shall be eliminated." The rate was available for commercial purposes such as electroplating, water supply and irrigation, and refrigeration by compression. Initially the Company proposes to cancel this rate and transfer its customers to Rate G-1. Based on a further review of these customers, the Company proposes to transfer customers who use this rate for lighting to Rate S-2. It proposes that larger customers on this rate whose use indicates large demands will be subsequently transferred to Rate G-2 (Exh. BE-300, p. 20; Exh. BE-315). No party objected to the Company's proposal.

Based on the evidence in this record and our analysis of bill impacts which indicates that the goal of continuity will not be violated as a result of the transfer, we find the Company's proposal to eliminate this rate acceptable. The customers which it proposes to transfer to Rate G-1 may be so transferred, subject to the Company's continued evaluation which will place lighting customers on Rate S-2 and large customers on Rate G-2.

15. Rate S-1, Street and Fire Alarm Lighting Service

Rate S-1 is the Company's street and fire alarm lighting

service rate which is available only for lighting on public property. Under this rate the Company supplies the luminaire (light bulb), the bracket to hold it (together with the luminaires referred to as the fixture), the mounting of the bracket on a pole and the electricity to operate it. The Company has three types of luminaires served under this rate: incandescent, mercury vapor, and high-pressure sodium. Each of these different types of luminaires is available in several sizes. Both the mercury vapor and high-pressure sodium luminaires are still installed by the Company; incandescent luminaiares are no longer installed, although burned-out luminaires are replaced.

The Company developed the rates for its different types of luminaires based on marginal cost. It was able to calculate these costs directly for mercury vapor and high-pressure sodium luminaires. It took the installed cost of the luminaire and added to it the cost of mounting the fixture and installing it on a nonline pole. This total was multiplied by the appropriate economic carrying charge rate. To this resulting figure BECo added annual marginal O&M expense associated with the light and the marginal cost of the electricity used by the luminaire. This provided the annual marginal cost of the light which, when divided by 12, gave the monthly cost of the light.

Since the Company no longer provides incandescent luminaires, it developed the costs for these lights from the marginal costs of the mercury vapor and high-pressure sodium

lights. It first determined the ratio, under existing rates, of the fixture cost of the incandescent lights to the appropriate mercury vapor or high-pressure sodium light. This ratio was then applied to the new marginal cost calculated for this case to determine the marginal cost of the fixture and mounting for incandescent luminaires. Finally, the marginal cost of the electricity used by the incandescent luminaires was added to the installed cost to determine the marginal cost.

The revenues based on marginal cost for all light types did not meet the allocated revenue requirement, so an equal monthly charge per installation was developed to reconcile the marginal-cost-based rates with the allocated revenue requirement (Exh. BE-300, pp. 24-25; Exh. BE-320). No party objected to the Company's proposal.

Based on the evidence in this record, we find the Company's proposed rate design method for this rate to be reasonable. We find that in its compliance filing the Company must revise its proposed rates to reflect the marginal costs found to be appropriate in this Order and the allocated revenue requirement shown in Schedule 10.

16. <u>Rate S-2, Street Lighting Energy Rate</u>

The Company's Rate S-2 serves public authorities which own their own streetlights and require only the electricity from the Company to operate them. The rate consists of a service charge and an energy rate. The Company moved the energy rate part of the way toward marginal cost so as to maintain continuity (Exh.

BE-300, p. 25). No party objected to the Company's proposal.

Based on the evidence in this record, we find the Company's proposed rate design method for this rate to be reasonable. We find that in its compliance filing the Company must revise its proposed rates to reflect the marginal costs found to be appropriate in this Order and the allocated revenue requirement shown in Schedule 10.

17. <u>Rate S-3, Outdoor Lighting</u>

The Company's Rate S-3 is similar to its Rate S-1 except that it is available to all customers, public and private. The Company developed the rates for this class in the same manner as for the incandescent fixtures in Rate S-1, with the remaining revenue requirement recovered through an equal charge per installation (Exh. BE-300, pp. 25-26; Exh. BE-321). No party objected to the Company's proposal.

Based on the evidence in this record, we find the Company's proposed rate design method for this rate to be reasonable. We find that in its compliance filing the Company must revise its proposed rates to reflect the marginal costs found to be appropriate in this Order and the allocated revenue requirement shown in Schedule 10.

18. <u>Rate T-1, Optional TOU Rate for Rate G-1</u>

Rate T-1 is the Company's optional TOU rate for customers on its Rate G-1. It uses the same time periods as Rate G-3, has its energy charges set at marginal cost by daily and seasonal time periods, and has its customer charge set equal to the

marginal customer cost for Rate G-1 plus the additional cost of a TOU meter (Exh. BE-300, p. 20; Exh. BE-325, pp. 6-15; 95-99). No party objected to the Company's proposal.

Based on the evidence in this record, we find the Company's proposed rate design method for this rate to be reasonable. We find that in its compliance filing the Company must revise its proposed rates to reflect the marginal costs found to be appropriate in this Order.

19. Rate T-2, Optional/Mandatory TOU Rate for Rate G-2

Rate T-2 is the Company's TOU rate for Rate G-2 customers. The largest customers will be transferred to this rate on a mandatory basis. Smaller customers, and larger customers who wish to be transferred ahead of the Company's schedule, may also avail themselves of this rate. This rate is designed so that the demand and energy charges are the same as for Rate G-2. The long hours' use blocks from Rate G-2 are the off-peak energy charges and the first energy blocks from Rate G-2 comprise the peak energy charges. The customer charge is equal to the proposed G-2 customer charge plus the additional cost of a TOU meter (Exh. BE-300, p. 20; Exh. BE-325, pp. 95-99). No party objected to the Company's proposal.

Based on the evidence in this record, we find the Company's proposed rate design method for this rate to be reasonable. We find that in its compliance filing the Company must revise its proposed rates to reflect the rates for Rate G-2 found to be appropriate in this Order.

20. Rate T-3, Optional TOU Rate for Rate G-3

Rate T-3 is an optional TOU rate established many years ago for Rate G-3 customers. It has up to three daily time periods, and the demand and energy rates that a customer pays are a function of that customer's load factor. In D.P.U. 1720, the Department ordered the Company to "propose a plan in its next rate case whereby Rate T-3 is modified so that it reflects the same time periods as Rate G-3 [and] ... explain how modifications over time will enable Rate T-3 to be consolidated with Rate G-3 at the time Rate G-3 is based upon full marginal costs." Id., p. 177. The Company proposes to combine Rate T-3 with Rate G-3 in this case. There are presently two customers on Rate T-3.

Amstar alleges that the Department, in D.P.U. 1720, did not order BECo to terminate the T-3 rate schedule altogether. Instead, according to Amstar, the Order requires BECo to propose an orderly transition plan. Amstar argues that consolidation of Rate T-3 with Rate G-3 in this case does not constitute an orderly transition (Amstar Brief, p. 2). Further, Amstar contends that the Company has been arbitrary and capricious and has provided no explanation of its reasoning behind the decision to cancel Rate T-3 (Amstar Brief, pp. 4-6). Finally, Amstar maintains that if BECo's proposal is allowed, Amstar will receive a 19 percent increase in base rates (Amstar Brief, p. 7; Exh. Amstar-1).

The Company argues that Rate T-3 should be consolidated with

Rate G-3. It states that in D.P.U. 1720 the Department specifically ordered the Company to align Rate T-3's structure with that for Rate G-3. In a letter from the Department, the Company argues, it was told there was no further need for Rate T-3. On this basis, the Company contends that the Department has directed it to eliminate the rate. The Company further argues that the only source of harm Amstar has alleged from the consolidation with Rate G-3 is the change in rating periods. The Company maintains that Amstar has not shown that any harm will actually result and, in any case, the Company was under a Department directive to make the rating periods the same in the two rates.

As with Bentley's contentions regarding the elimination of Rate G-6, Amstar's contentions concern continuity. We have examined the bill impacts produced by the transfer of Rate T-3 customers to Rate G-3 in this case and find that the change in rates does not violate continuity.

Therefore, we find that the Company's proposal to eliminate Rate T-3 and transfer its customers to Rate G-3 is reasonable.

21. Auxiliary Service Charges

Auxiliary rates are rates "[a]vailable to a customer having another source of electrical power from which all or a portion of its electrical requirements are supplied. If such other source is used only in case of failure of the Company's service, the Company's service is not considered Auxiliary Service" (Exh. BE-302, M.D.P.U. No. 726).

There are four types of auxiliary service which the Company proposes. First, there is segregated service in which a customer who generates his own power has the portion of his load served by the Company electrically segregated from the rest of his load. In this case the Company would serve the segregated load under its regular general service rates.

Second is partial requirements service. This would apply to a customer who is capable of supplying part of its own energy requirements but wishes to have the option to have all of his requirements served by the Company. The Company proposes to have the customer contract for the maximum amount of power it would require from the Company. The Company would then bill the customer each month under the applicable general service rate for the power actually used and would charge an additional rate per KW for the power contracted for but not demanded by the customer.

Third is back-up service. This would apply to a customer who wishes the Company to supply power when the customer's generating unit is out of service. The Company proposes to offer these customers a choice between firm or interruptible service. The rate would consist of a service charge, a demand charge to cover distribution costs, and an energy charge based on, in the firm case, marginal production and transmission capacity costs and marginal energy costs. In the case of interruptible service the energy charge would be based on marginal energy costs.

Fourth is maintenance service. This would apply to a customer who provides all of his own energy requirements and is disconnected, under control of the Company, from the Company's system. It only applies for scheduled outages of the customer's equipment where the outage is planned with the Company and does not occur during peak summer or winter periods. The proposed rate consists of a service charge, demand charge, and energy charge.

The Consortium argues that the Company's proposed auxiliary service rates discriminate against cogenerators in violation of the Public Utilities Regulatory Policies Act (See D.P.U. 84-276-A). According to the Consortium, the Company's proposal would, in effect, establish a 100 percent ratchet for auxiliary service customers, in contrast to Rates G-2 and G-3, which have no ratchet provisions. The Consortium also contends that the Company has not shown that the load characteristics of auxiliary service customers are uniquely different from those of its regular general service customers, but only alleges that they are different on average. Finally, the Consortium maintains that the Company has conducted no COSS to show that the auxiliary rates are cost-based (Consortium Brief, pp. 20-26).

CMC states that the Company's proposal, while a significant improvement over its current tariff, does not meet the standards set by the Department in D.P.U. 84-276, D.P.U. 84-165-A, and D.P.U. 85-146-A. According to CMC, this standard requires that the availability and applicability of rate schedules be

3. Standards for System Performance

BECo's standards for distribution circuit performance, against which "problem" circuits can be measured, do not appear to be consistently useful in identifying problems. It is not clear that the list of 20 or 40 worst circuits identifies all major distribution problems. Therefore, it is difficult for the Department to assess BECo's performance. In addition, the Company has not shown how it determines the order of priority in which circuits on its lists receive attention, in spite of the Department's inquiries about this specific subject.

The Company's system for identifying its "problem" circuits ranks the service outages on these circuits according to "kilovolt-ampere-hours" ("KVA-hours") (Tr. 23, p. 2318; HO-RR-25). KVA-hours is a measurement which expresses the duration and magnitude of an outage as the product of the number of hours the circuit was out and the electrical load (in KVA) which was out of service. For example, a fifteen-minute outage of a circuit which has a connected load of 10,000 KVA would result in an outage statistic of 2,500 KVA-hours. The list of the Company's 40 worst circuits ranks those circuits which have had the most KVA-hours out in the most recent twelve-month period (Tr. 23, p. 2319).

The Department has two concerns about the Company's list of its 40 worst circuits. First, it appears that, by the Company's own standard for measuring the magnitude of outages, the performance of the Company's distribution system deteriorated

quite significantly from 1984 to 1985. The circuit at the top of the list for the twelve months ending December 31, 1985, had outages totalling 256,985 KVA-hours, while the 40th circuit on the list totalled 45,570 KVA-hours. The 40th circuit for 1984, by comparison, had 34,053 KVA-hours, and the last 18 circuits on the list all had fewer than 44,000 KVA-hours (HO-RR-25). This evidence suggests that there were additional circuits, which did not perform poorly enough to make it onto the 1985 list, but which experienced a larger number of KVA hours of outages than some of the circuits on the 1984 list.

Second, it appears that the Company's method of ranking the performance of its "problem" circuits may emphasize the performance of large circuits (i.e., those with large connected KVA loads), and may therefore fail to disclose problems with smaller ones, such as those found in older urban areas. To the extent that the Company uses its "list of 40" to direct resources toward distribution problems, an emphasis on large circuits may be reflected in the way the distribution system is maintained.

Mr. Carr illustrated the potential for emphasizing large circuits when he explained that a large circuit could get onto the list of 40 as a result of a single severe problem that took time to repair (Tr. 23, p. 2321). Many of the Company's suburban circuits have connected loads of 18,000 to 22,000 KVA (HO-RR-25). By comparison, the circuits in Brookline and the South End, on which the Department focused in this proceeding, have loads of 2,500 to 6,500 KVA (id.). Simple arithmetic

suggests that, in order for a 5,000 KVA circuit to have the same number of KVA-hours out as an 20,000 KVA circuit, it must have outages that are longer, more frequent, or both.

For example, in order to have 122,191 KVA-hours out in 1985, circuit 036-03 in Brookline, which has a connected load of 5,975 KVA, must have had the equivalent of over 20 hours of full-circuit outages (HO-RR-25, p. 15). By comparison, the "worst" circuit on the Company's list, circuit 146-H2 in Millis and Norfolk, with a connected load of 22,250 KVA, experienced 256,985 KVA-hours of outages, which is equivalent to 11.5 hours of full-circuit outages (id.).

The Company has not explained how its method of identifying its worst circuits takes the size of those circuits into account. Although Mr. Carr explained that the Company reviews its records for each circuit on the list of 40 before deciding what action to take, he did not indicate that smaller circuits are accorded any special attention. The Department does not find that it is improper to consider the load served by a circuit in determining the seriousness of circuit problems. However, it is not clear from the evidence presented by the Company that BECo's focus on problems at the circuit level, rather than on a broader geographical level, accords equal treatment to customers in different parts of its service territory.

In addition, the Company's tracking system does not specifically distinguish between circuits which have been on the list of the 40 worst performers for longer than a year and those

which have just made it onto the list. Mr. Carr testified that each January the Company compares the circuits on the current twelve-month list to those on the twelve-month list for the previous year, to see whether any circuits are still on the list and to see what improvement has been made (Tr. 23, p. 2319). He added:

> Most of the time, I don't recall having a circuit remain on the list over 12 months. There may be an exception to that here and there; but for the most part, I don't recall a circuit lingering on that list for over the 12-month period (Tr. 23, p. 2320).

However, a comparison of the report for 1985 with that for 1984 shows that 11 of the 40 worst circuits for 1984 were still on the report for 1985 (HO-RR-25). More significantly, five out of the worst 20 circuits in the 1985 report were among the worst 20 a year earlier (id.). The Company did not provide a report for 1983, but it provided a report for the twelve months ending January 31, 1984. This report, again, shows that six of the worst 20 circuits for the February 1983 to January 1984 period were still among the worst 20 circuits in 1985 (id.).

The Department understands that the work required to correct a problem on a circuit may take longer than a year to plan and complete, but the Company has presented no testimony that this is the case, or that the circuits that have been among the 20 worst performers two years running are receiving any special attention.

4. Promptness in Addressing Problems

The fact that "problem" circuits in BECo's distribution system remain among the worst 20 circuits over what is nearly a three-year period raises concern about the Company's effectiveness in dealing with distribution problems. The Department finds further cause for concern in BECo's slowness in resolving the problems in the circuits served by substation 036. In this instance, the record shows that BECo is still planning solutions two years after three of the station 036 circuits first showed up on the Company's list of its 40 worst circuits (HO-RR-25).

The Department notes a similar situation in the case of the circuits served by substation 318, in the South End. Circuit 318-05, served by this substation, showed up among the 40 worst circuits in the Company's system as early as the report for the twelve months ending March 31, 1984 (HO-RR-25). Circuit 318-08 was on the list for the twelve months ending June 30, 1984, and circuit 318-02 was on the list for the twelve months ending December 31, 1984 (id.). Circuits 318-07 and 318-11 made the list for the twelve months ending June 30, 1985 (id.). In each instance, the circuit had experienced the equivalent of between eight and fourteen hours of full-circuit outages during the preceding twelve months (id.). These outages do not include planned outages or those of less than five minutes' duration (id.).

The Company has attributed the problems in the area served by substation 318 to unexpectedly high load growth, resulting

from residential development of the area (Exh. HO-17). Yet the Company's own records show a history of substandard performance by circuits in this area, dating back at least to the April 1983 to March 1984 period (HO-RR-25).

High load growth may be beyond Company's control, but the Department finds that it is BECo's responsibility to track development activity in its territory and to respond to the service needs of its customers in a timely fashion.

E. Conclusion

In conclusion, the Department finds that BECo does not have a clearly-articulated standard for distribution-system reliability. Although BECo routinely calculates annual indices of its distribution system's overall reliability, the Company has not shown how or whether these indices can be used to determine whether the performance of individual circuits is substandard. From the evidence presented in this proceeding, the Department finds that the Company appears to rely primarily on periodically prepared lists of its 20 worst or 40 worst distribution circuits to determine which of its distribution circuits require special attention. These lists are not so much a standard of reliability as lists of priorities for distribution-system maintenance or upgrading. The Department has found that, even as a list of priorities, the Company's listing of its worst circuits has at least two failings: first, it appears that these lists understate distribution problems in areas which are served by many relatively small circuits; and

second, BECo appears to have no formal system for addressing the problem of circuits which appear on the lists year after year.

The Department is unable to determine, based on the limited nature of our investigation in this proceeding, whether service in all 40 of the Company's worst circuits is as bad as that in the areas served by substation 318, in the South End neighborhood of Boston, and substation 036, in Brookline. The Department does, however, find that the performance of certain circuits in these two areas is below any acceptable standard and that the Company has not satisfactorily explained why certain circuits have remained high on the Company's lists of its 40 worst circuits for three years in a row.

Accordingly, the Department finds that the Company, in its next rate case, must show that it has completed the following actions:

1. Identified problems on those distribution circuits which have been among its 40 worst circuits, on a twelve-month KVA-hour-outage basis, for more than one calendar year, and implemented detailed plans to remedy these problems.

2. Developed and implemented a method of identifying service problems which affect smaller distribution circuits, and of ensuring that areas served by circuits which have smaller connected loads receive the same priority as areas served by a single larger circuit.

XIII. SCHEDULES

SCHEDULE 1

REVENUE REQUIREMENT AND CALCULATION OF REVENUE INCREASE

	PER COMPANY*	DPU ADJ.	PER ORDER
ELECTRIC COST OF SERVICE			
OPERATIONS AND MAINTENANCE EXPENSE	$770,572,734	($12,425,678)	$758,147,056
DEPRECIATION AND AMORTIZATION	$96,427,823	($2,941,201)	$93,486,622
TAXES OTHER THAN INCOME TAX	$68,699,422	($3,582,517)	$65,116,905
MASSACHUSETTS FRANCHISE TAX	$13,109,487	($1,149,133)	$11,960,354
FEDERAL INCOME TAX	$86,744,468	($7,603,724)	$79,140,744
TAX CREDITS	($4,916,977)	$0	($4,916,977)
RETURN ON RATE BASE	$164,707,514	($16,367,218)	$148,340,296
COST OF SERVICE	$1,195,344,471	($44,069,472)	$1,151,274,999
ELECTRIC REVENUES			
RETAIL ELECTRIC REVENUES	$1,021,075,879	$0	$1,021,075,879
OTHER OPERATING REVENUES	$123,091,223	($1,008,147)	$122,083,076
TOTAL RETAIL REVENUES	$1,144,167,102	($1,008,147)	$1,143,158,955
BASE REVENUE SHORTFALL	$51,177,369	($43,061,325)	$8,116,044
FUEL AND PURCHASED POWER CLAUSE REVENUE ADJUSTMENT	($15,463,873)	$7,425,152	($8,038,721)
REVENUE INCREASE	$35,713,496	($35,636,173)	$77,323

*All numbers per Company are from original filing test year ending June 30, 1985

SCHEDULE 2

OPERATIONS AND MAINTENANCE
EXPENSES

	EXPENSES		
	PER COMPANY	DPU ADJ.	PER ORDER
O&M PER BOOK	$806,971,278	$0	$806,971,278
ADJUSTMENTS:			
ANNUALIZED PURCHASED POWER	$3,549,932	$6,414,693	$9,964,625
BOOKING ERRORS	$0	($1,152,000)	($1,152,000)
CIVIL PENALTIES	($974)	$0	($974)
COAL CONVERSION	$2,817,323	$0	$2,817,323
COMM. ON ENERGY AWARENESS	($224,673)	$0	($224,673)
DONATIONS	$1,837,981	($1,009,912)	$828,069
EEI DUES EXPENSE	($32,524)	($286,803)	($319,327)
EEI MEDIA EXPENSE	($147,156)	$0	($147,156)
EPRI LIFE EXTENSION	$0	($179,277)	($179,277)
FUEL & PP REV. NORM.			
RETAIL PORTION ONLY	($7,717,000)	$0	($7,717,000)
SYSTEM	($63,312,336)	$0	($63,312,336)
IMPACT 2000 ADVERTISING	$0	($334,000)	($334,000)
IMPACT 2000 WRITEOFF	$0	($392,000)	($392,000)
INFLATION ALLOWANCE	$6,371,408	($1,301,408)	$5,070,000
INSURANCE PROCEEDS	($194,174)	$0	($194,174)
JOYCE CAPELESS	($35,000)	$0	($35,000)
MYSTIC SCRUBBER AMORTIZATION	($154,034)	$0	($154,034)
NEW BOSTON TRANSFORMER RENTAL	$0	($1,186,152)	($1,186,152)
NUCLEAR INS.	$450,924	$0	$450,924
OTHER INJ. AND DAMAGE INS.	$905,757	$0	$905,757
OTHER PROPERTY INS.	$549,140	$0	$549,140
PILGRIM RECONVEYANCE AMORT.	$436,315	($436,315)	$0
PILGRIM REFUELING	($2,507,839)	($4,977,168)	($7,485,007)
PROP. TAX CASE LEGAL FEES	($636,943)	$0	($636,943)
RATE CASE EXPENSE	$176,000	$25,500	$201,500
RATE S LITIGATION COSTS	$0	$0	$0
RESDL CONSERVATION SERVICE	($214,000)	$0	($214,000)
SETTLEMENT WRITEOFFS	$0	($393,000)	($393,000)
STORM COST 1984	$50,994	$0	$50,994
STORM COST 1985	$2,038,776	$49,995	$2,088,771
TRANS. EXP. ANNUALIZED	$6,559,339	($6,417,147)	$142,192
UNCOLLECTIBLES	$465,000	($487,000)	($22,000)
WAGE & SALARY	$11,542,234	$599,239	$12,141,473
WHOLE LIFE INS.	$64,063	$0	$64,063
WOBURN&TEWKSBURY TRANS. LINE	$962,923	($962,923)	$0
ADJ. TO O&M	($36,398,544)	($12,425,678)	($48,824,222)
O&M	$770,572,734	($12,425,678)	$758,147,056

SCHEDULE 3

DEPRECIATION AND AMORTIZATION EXPENSES

	PER COMPANY	DPU ADJ.	PER ORDER
DEPRECIATION			
PRODUCTION			
STEAM REGULAR	$11,923,921	$0	$11,923,921
STEAM MYSTIC 7 & WYMAN 4	$6,860,280	$0	$6,860,280
NUCLEAR	$22,792,607	($47,015)	$22,745,592
NUCLEAR INTANGIBLES	$1,858,236	($1,012,875)	$845,361
DECOMMISSIONING	$4,894,913	$0	$4,894,913
OTHER PRODUCTION	$1,072,284	$0	$1,072,284
NEW BOSTON GAS CONVERSION	$3,203,427	($3,203,427)	$0
PRODUCTION	$52,605,668	($4,263,317)	$48,342,351
TRANSMISSION	$5,319,055	$0	$5,319,055
TRANSMISSION INTANGIBLES	$33,104	$0	$33,104
DISTRIBUTION	$22,685,607	$0	$22,685,607
GENERAL			
OTHER	$3,539,050	$0	$3,539,050
INTANGIBLES	$158,680	$0	$158,680
ACRS TAX LEASE	($87,318)	$0	($87,318)
GENERAL	$3,610,412	$0	$3,610,412
ADJUSTMENTS			
BOOKING ERRORS	$0	$28,495	$28,495
ADJUSTMENTS	$0	$28,495	$28,495
DEPRECIATION	$84,253,846	($4,234,822)	$80,019,024
AMORTIZATION			
PILGRIM 1 OUTAGE EXPENSE	$0	$3,664,087	$3,664,087
PILGRIM 2	$12,173,977	$0	$12,173,977
SALES OF UTILITY PROPERTY	$0	($897,000)	($897,000)
DC DISCONTINUANCE EXPENSE	$0	($1,473,466)	($1,473,466)
AMORTIZATION	$12,173,977	$1,293,621	$13,467,598
DEPRECIATION AND AMORTIZATION	$96,427,823	($2,941,201)	$93,486,622

SCHEDULE 4

RATE BASE AND RETURN ON RATE BASE

	PER COMPANY	DPU ADJ.	PER ORDER
PLANT IN SERVICE	$2,135,634,630	($1,334,413)	$2,134,300,217
ACCUM. DEPR.	$619,343,058	$0	$619,343,058
NET PLANT IN SERVICE	$1,516,291,572	($1,334,413)	$1,514,957,159
ADDITIONS TO PLANT			
BOOKING ERRORS	$0	$905,000	$905,000
CASH WORKING CAPITAL (SCHEDULE 6)	$76,471,732	($991,478)	$75,480,253
EEI DUES	($8,829)	($38,260)	($47,089)
EPRI LIFE EXTENSION	$0	$179,277	$179,277
MATERIALS & SUPPLIES	$67,264,422	$0	$67,264,422
NUCLEAR FUEL	$68,254,133	($2,897,544)	$65,356,589
PILGRIM TRANS. LINE	$1,742,803	$0	$1,742,803
PLANT HELD FOR FUTURE USE	$0	$0	$0
ADDITIONS TO PLANT	$213,724,261	($2,843,005)	$210,881,255
DEDUCTIONS FROM PLANT			
ACCUM. DEF. INCOME TAXES	$302,231,240	$0	$302,231,240
CUST. ADV. CONST.	$1,484,891	$0	$1,484,891
UNAMORT. ITC	$3,866,983	$0	$3,866,983
UNCLAIMED FUNDS	$88,038	$0	$88,038
DEDUCTIONS FROM PLANT	$307,671,152	$0	$307,671,152
RATE BASE	$1,422,344,681	($4,177,418)	$1,418,167,262
COST OF CAPITAL (SCHEDULE 5)	11.58%	-1.12%	10.46%
RETURN ON RATE BASE	$164,707,514	($16,367,218)	$148,340,296

SCHEDULE 5

COST OF CAPITAL

	PER COMPANY			
	CAPITAL			RATE OF
	PRINCIPAL	PERCENTAGE	COST	RETURN
FIRST MORTAGE BONDS	$744,875	49.16%	9.51%	4.67%
SECURED NOTES	$0	0.00%	0.00%	0.00%
NUCLEAR FUEL	$50,000	3.30%	9.67%	0.32%
PREFERRED STOCK	$83,000	5.48%	6.66%	0.36%
PREFERENCE STOCK	$73,475	4.85%	11.41%	0.55%
COMMON EQUITY	$563,994	37.22%	15.25%	5.68%
TOTAL	$1,515,344	100.00%		11.59%
WEIGHTED COST OF				
DEBT				4.99%
EQUITY				6.59%
COST OF CAPITAL				11.58%

	PER ORDER			RATE OF
	CAPITAL			RETURN
	PRINCIPAL	PERCENTAGE	COST	PER ORDER
FIRST MORTAGE BONDS	$744,875	47.60%	9.42%	4.48%
SECURED NOTES	$0	0.00%	0.00%	0.00%
NUCLEAR FUEL	$0	0.00%	0.00%	0.00%
PREFERRED STOCK	$83,000	5.30%	6.60%	0.35%
PREFERENCE STOCK	$73,475	4.70%	11.41%	0.54%
COMMON EQUITY	$663,502	42.40%	12.00%	5.09%
TOTAL	$1,564,852	100.00%		10.46%
WEIGHTED COST OF				
DEBT				4.48%
EQUITY				5.97%
COST OF CAPITAL				10.46%

SCHEDULE 6

CASH WORKING CAPITAL

	PER COMPANY	DPU ADJ.	PER ORDER
FUEL & PURCHASED POWER	$389,641,641	$6,575,529	$396,217,170
@ 30/365	$32,025,340	$540,454	$32,565,795
O&M EXPENSES	$770,572,734	($12,425,678)	$758,147,056
LESS:			
NORMALIZED FUEL & PURCHASED POWER	($409,757,304)	$0	($409,757,304)
MYSTIC SCRUBBER	($305,810)	$0	($305,810)
NET O&M EXPENSE	$360,509,620	($12,425,678)	$348,083,942
@ 45/365	$44,446,392	($1,531,933)	$42,914,459
CASH WORKING CAPITAL	$76,471,732	($991,478)	$75,480,253

SCHEDULE 7

TAXES OTHER THAN INCOME TAXES

	ELECTRIC	RETAIL PERCENT	PER COMPANY	DPU ADJ.	PER ORDER
PAYROLL TAX	$8,531,000	98.56%	$8,408,061	($12,813)	$8,395,248
PROPERTY TAX	$61,077,000	98.28%	$60,029,406	($3,569,704)	$56,459,702
STATE SALES TAX	$180,000	98.11%	$176,599	$0	$176,599
EXCISE TAX	$87,000	98.11%	$85,356	$0	$85,356
TAXES OTHER THAN INCOME TAX	$69,875,000		$68,699,422	($3,582,517)	$65,116,905

SCHEDULE 8

INCOME TAXES

	PER COMPANY	DPU ADJ.	PER ORDER
RATE BASE	$1,422,344,681	($4,177,418)	$1,418,167,262
RETURN ON RATE BASE	$164,707,514	($16,367,218)	$148,340,296
ADD:			
PRE 1954 NONDEDUCTIBLE DEPRECIATION	$3,323,586	$0	$3,323,586
AFUDC DEPRECIATION NOT PREVIOUSLY NORMALIZED	$2,869,738	$0	$2,869,738
PILGRIM 2 AMORTIZATION	$12,173,977	$0	$12,173,977
BOOK DEPRECIATION ON 50% ITC BASIS ADJ.	$446,403	$0	$446,403
AMORTIZATION 50% ITC POST 1982 LEASED PROPERTY	$52,236	$0	$52,236
INCOME ADDITIONS	$18,865,940	$0	$18,865,940
DEDUCT:			
WEIGHTED COST OF DEBT	4.99%	-0.51%	4.48%
INTEREST CHARGES	($70,975,000)	$7,441,106	($63,533,893)
PREFERRED STOCK DIVIDEND DEDUCTION	($1,045,861)	$0	($1,045,861)
ADDITIONAL FY PROPERTY TAX DEDUCTION	($4,805,143)	$0	($4,805,143)
INCOME DEDUCTIONS	($76,826,004)	$7,441,106	($69,384,897)
TAX CREDITS	($4,916,977)	$0	($4,916,977)
NET INCOME	$101,830,473	($8,926,112)	$92,904,361
STATE TAXABLE INCOME (NET INCOME * 1.98059)	$201,684,417	($17,678,969)	$184,005,449
MASSACHUSETTS FRANCHISE TAX (STATE TAXABLE INCOME * 6.5%)	$13,109,487	($1,149,133)	$11,960,354
FEDERAL TAXABLE INCOME (STATE TAXABLE INCOME - MASS. FRANCHISE TAX)	$188,574,930	($16,529,836)	$172,045,095
FEDERAL INCOME TAX (FEDERAL TAXABLE INCOME * 46%)	$86,744,468	($7,603,724)	$79,140,744

SCHEDULE 9

REVENUES

	PER COMPANY	DPU ADJ.	PER ORDER
RETAIL ELECTRIC REVENUES			
PER BOOK	$1,099,645,302	$0	$1,099,645,302
ANNUALIZATIONS	$6,956,000	$0	$6,956,000
FUEL NORMALIZATION	($85,790,000)	$0	($85,790,000)
OTHER	$264,577	$0	$264,577
RETAIL ELECTRIC REVENUES	$1,021,075,879	$0	$1,021,075,879
OTHER OPERATING REVENUES			
OTHER SALES OF ELECTRICITY	$102,125,350	($740,178)	$101,385,172
NON. RESIDENTIAL INTEREST CHARGES	$4,414,180	$0	$4,414,180
MISC. SERVICE REVENUES	$124,420	$0	$124,420
RENT FROM ELEC. PROPERTY	$7,694,888	($267,969)	$7,426,919
OTHER ELECTRIC REVENUES	$8,732,385	$0	$8,732,385
OTHER OPERATING REVENUES	$123,091,223	($1,008,147)	$122,083,076
TOTAL RETAIL REVENUES	$1,144,167,102	($1,008,147)	$1,143,158,955

REVENUE ALLOCATION, BOSTON EDISON COMPANY, D.P.U. 85-271 — SCHEDULE 10

TEST YEAR REVENUES:	$1,144,167,102
REVENUE INCREASE:	$8,116,044
REVENUE REQUIREMENT:	$1,152,283,146
UNDERCOLLECTION:	$25,312
SSI REVENUE DEFICIENCY:	$448,411

A / C	D	E	F	H	I	J	K	L	M	N	O	P
		RATE BASE (EXH BE-201, SCH.2, P.1, LINE 260)	KWH BILLING UNITS (EXH BE-330)	REVENUE REQUIREMENT PER COMPANY (EXH BE-201, SCH.1, P.1, LINE 100)	REVENUE REQUIREMENT PER ORDER H/H TOTAL * REVENUE REQUIREMENT PER ORDER	OPERATING REVENUES (EXH BE-201, SCH.2, P.1, LINE 10, AT CURRENT RATES)	REVENUE INCREASE I-J	SSI REVENUE DEF. ON PERCENTAGE OF RETAIL RATE BASE (COLUMN D)	INCREASE IN REVENUE REQUIREMENT (COLUMN K + COLUMN L)	PERCENTAGE INCREASE IN REVENUE REQUIREMENT (COLUMN M/ COLUMN J)	BASE RATE REVENUES (BE-201, SCH. 1, LINE 180)	NEW TOTAL BASE RATE REVENUE REQUIREMENT (COLUMN M + COLUMN O)
RES. REG.	R-1	$414,880,419	2,867,972,962	$358,092,277	$345,191,820	$332,996,998	$12,194,822	$130,795	$12,325,617	3.701%	$204,468,298	$216,793,915
SSI	R-2							$-448,411				$0
G.S. SMALL	G-1	$64,266,484	403,034,823	$54,629,142	$52,661,099	$55,857,683	$-3,196,584	$20,261	$-3,176,323	-5.686%	$56,802,043	$53,625,720
G.S. MEDIUM	G-2	$622,058,987	3,862,441,695	$501,507,144	$483,440,043	$483,215,737	$224,306	$196,110	$420,416	.087%	$278,483,120	$278,903,536
G.S. LARGE	G-3	$277,619,727	2,838,197,657	$253,547,171	$244,413,005	$248,045,897	$-3,632,892	$87,522	$-3,545,370	-1.429%	$122,856,438	$119,311,068
STREET LIGHTING	S-1	$35,058,133	96,960,850	$20,545,865	$19,805,690	$17,694,255	$2,111,435	$11,052	$2,122,487	11.995%	$13,319,122	$15,441,609
	S-2	$4,772,105	35,771,789	$4,079,067	$3,932,117	$3,836,823	$95,294	$1,504	$96,798	2.523%	$2,175,075	$2,271,873
	S-3	$3,697,060	17,452,582	$2,945,434	$2,839,323	$2,519,659	$319,664	$1,166	$320,830	12.733%	$1,713,967	$2,034,797
TOTALS		$1,422,353,715	10,121,832,366	$1,195,346,100	$1,152,283,146	$1,144,167,102	$8,116,044	$0	$8,564,455	.749%	$659,818,063	$668,382,518

SCHEDULE 11

TRANSMISSION MARGINAL COSTS, D.P.U. 85-271

YEAR	PEAK LOAD	CUMULATIVE ADDITIONS
1965	1,300	30,058,343
1966	1,377	75,913,179
1967	1,404	85,901,761
1968	1,569	123,910,347
1969	1,654	145,122,246
1970	1,744	143,668,389
1971	1,877	153,947,226
1972	1,912	168,217,018
1973	2,127	169,233,741
1974	1,979	185,274,103
1975	2,110	217,338,514
1976	2,130	260,927,033
1977	2,187	266,694,216
1978	2,184	283,099,388
1979	2,158	282,941,037
1980	2,271	282,469,090
1981	2,234	282,548,432
1982	2,367	287,578,012
1983	2,412	289,230,857
1984	2,592	290,409,003
TOTAL	39,588	4,024,481,935
MAXIMUM	2,592	290,409,003

20	20	= Total entries
1,979	201,224,097	= Mean
366	83,729,463	= St. Dev. (Sample)
356	81,609,386	= St. Dev. (Pop.)

Y = A + B*X   95 % confidence limits

-227,671,153	= A (Intercept)	q	1.320e12
216,679	= B (Slope)	q	37001.15
.8957	= R^2		
.9464	= R		

7.718175936e14 = residual variance
27,781,605 = s
2.1231 w (t.025)

SCHEDULE 12 p.1

HIGH TENSION DISTRIBUTION MARGINAL COSTS, D.P.U. 85-271

YEAR	PEAK LOAD	CUMULATIVE ADDITIONS
1975	1,784	27,259,700
1976	1,816	44,386,308
1977	1,853	55,337,329
1978	1,885	68,552,154
1979	1,860	81,549,662
1980	1,960	87,242,272
1981	1,933	98,484,908
1982	2,033	106,293,342
1983	2,096	124,513,907
1984	2,266	142,404,690
TOTAL	19,486	836,024,272
MAXIMUM	2,266	142,404,690

10	10	= Total entries
1,949	83,602,427	= Mean
147	35,936,853	= St. Dev. (Sample)
140	34,092,693	= St. Dev. (Pop.)

Y = A + B*X   95 % confidence limits

-361,870,358	= A (Intercept)	q	4.187e11
228,612	= B (Slope)	q	69936.48
.8799	= R^2		
.9380	= R		

1.745524261e14 = residual variance
13,211,829 = s
2.3416 w (t.025)

SCHEDULE 12 p. 2

SECONDARY DISTRIBUTION MARGINAL COSTS, D.P.U. 85-271

YEAR	PEAK LOAD	CUMULATIVE ADDITIONS
1975	1,784	43,831,716
1976	1,816	69,025,038
1977	1,853	88,962,362
1978	1,885	112,510,807
1979	1,860	138,484,445
1980	1,960	151,455,935
1981	1,933	169,680,724
1982	2,033	188,973,902
1983	2,096	223,114,778
1984	2,266	256,534,419
TOTAL	19,486	1,442,574,126
MAXIMUM	2,266	256,534,419

10	10	= Total entries
1,949	144,257,413	= Mean
147	67,795,678	= St. Dev. (Sample)
140	64,316,627	= St. Dev. (Pop.)

Y = A + B*X — 95 % confidence limits

-702,619,321	= A (Intercept)	q	1.283e12
434,608	= B (Slope)	q	124229.8
.8935	= R^2		
.9452	= R		

5.507698160e14 = residual variance

23,468,486 = s

2.3416 w (t.025)

CALCULATION OF MARGINAL COSTS

SCHEDULE 13

CAPACITY			PRODUCTION	TRANSMISSION	DISTRIBUTION HIGH TENSION	DISTRIBUTION SECONDARY
(1)	LONG RUN UNIT INVESTMENT		$264.00	$216.70	$228.60	$434.60
(2)	GENERAL PLANT LOADING		1.0220	1.0220	1.0220	1.0220
(3)	TOTAL INVESTMENT	(1)*(2)	$269.81	$221.47	$233.63	$444.16
(4)	ECONOMIC CARRYING CHARGE		.1589	.1485	.1506	.1517
(5)	A&G LOADING (plant)		.0049	.0049	.0049	.0049
(6)	TOTAL	(4)+(5)	.1638	.1534	.1555	.1566
(7)	ANNUALIZED COST	(3)*(6)	$44.19	$33.97	$36.33	$69.56
(8)	O&M		$1.41	$1.38	$7.99	$14.68
(9)	A&G LOADING (non-plant)		1.2500	1.1400	1.4900	1.4900
(10)	TOTAL O&M	(8)*(9)	$1.76	$1.57	$11.91	$21.87
(11)	M&S LOADING FACTOR		.0375	.0090	.0122	.0122
(12)	M&S EXPENSE	(3)*(11)	$10.12	$1.99	$2.85	$5.42
(13)	O&M EXPENSE ALLOWANCE	(10)*0.125	$.22	$.20	$1.49	$2.73
(14)	TOTAL WORKING CAPITAL	(12)+(13)	$10.34	$2.19	$4.34	$8.15
(15)	REVENUE REQUIREMENT FOR CASH WORKING CAPITAL	(14)*0.2062	$2.15	$.46	$.90	$1.70
(16)	GROSS CAPACITY COSTS	(7)+(10)+(15)	$48.11	$36.00	$49.14	$93.13
(17)	RESERVE REQUIREMENTS		1.18	1.00	1.00	1.00
(18)	TOTAL MARGINAL CAPACITY COSTS	(16)*(17)	$56.77	$36.00	$49.14	$93.13
(19)	SUMMER SEASONAL ASSIGNMENT		60.000%	60.000%	40.000%	40.000%
(20)	WINTER SEASONAL ASSIGNMENT		40.000%	40.000%	60.000%	60.000%
(21)	SUMMER MARGINAL CAPACITY COSTS	(18)*(19)	$34.06	$21.60	$19.66	$37.25
(22)	WINTER MARGINAL CAPACITY COSTS	(18)*(20)	$22.71	$14.40	$29.48	$55.88

ENERGY			SUMMER PEAK	SUMMER OFF-PEAK	WINTER PEAK	WINTER OFF-PEAK
(23)	FAD DISPATCH MODEL MARGINAL ENERGY COSTS		$.05230	$.03351	$.05185	$.03543
(24)	THIRTY DAY FUEL SUPPLY		$.00356	$.00356	$.00356	$.00356
(25)	CASH WORKING CAPITAL	(24)*.2062	$.00074	$.00074	$.00074	$.00074
(26)	REVENUE REQUIREMENT FOR CASH WORKING CAPITAL	(23)+(25)	$.05304	$.03425	$.05259	$.03617

* MARGINAL CAPACITY COSTS: EXHIBIT BE-305, MCUS-10, MCUS-1030.

** MARGINAL ENERGY COSTS: EXHIBIT HS-10, SCHEDULE 4, P. 1.1.

MARGINAL COSTS BY VOLTAGE LEVEL (SUMMER) SCHEDULE 14

DEMAND	PRODUCTION	TRANSMISSION	DISTRIBUTION HIGH TENSION	DISTRIBUTION SECONDARY
GENERATION	$34.06	$21.60	$19.66	$56.91
HIGH TENSION	$36.28	$23.01	$20.97	N/A
SECONDARY	$40.19	$25.49	N/A	$68.34

ENERGY	PEAK
GENERATION	$.05304
HIGH TENSION	$.05612
SECONDARY	$.06226
	OFF-PEAK
GENERATION	$.03425
HIGH TENSION	$.03558
SECONDARY	$.03629

MARGINAL COSTS BY VOLTAGE LEVEL (WINTER)

DEMAND	PRODUCTION	TRANSMISSION	DISTRIBUTION HIGH TENSION	DISTRIBUTION SECONDARY
GENERATION	$22.71	$14.40	$29.48	$95.36
HIGH TENSION	$23.98	$15.21	$31.25	N/A
SECONDARY	$26.66	$17.04	N/A	$102.43

ENERGY	PEAK
GENERATION	$.05259
HIGH TENSION	$.05505
SECONDARY	$.06145
	OFF-PEAK
GENERATION	$.03617
HIGH TENSION	$.03741
SECONDARY	$.04024

MARGINAL LOSS FACTORS

	DEMAND PRODUCTION	DEMAND TRANSMISSION	DEMAND HIGH TENSION	DEMAND SECONDARY	ENERGY
SUMMER					
GENERATION	1.0000	1.0000	1.0000	1.0000	1.0000
HIGH TENSION	1.0650	1.0650	1.0670	1.0670	1.0430
SECONDARY	1.1800	1.1800	1.2010	1.2010	1.1420
WINTER					
GENERATION	1.0000	1.0000	1.0000	1.0000	1.0000
HIGH TENSION	1.0560	1.0560	1.0600	1.0600	1.0440
SECONDARY	1.1830	1.1830	1.2000	1.2000	1.1400

SCHEDULE 15
PAGE 1

RESIDENTIAL RATE R-1, REGULAR
VOLTAGE LEVEL: SEC.
(SUMMER)

	MARGINAL COSTS	AVERAGE CLASS CP OR NCP	KW BILLING UNITS	KWH BILLING UNITS	COINCIDENCE FACTOR, OR PERCENTAGE TIME	WEIGHTED RATES	REVENUES
MARGINAL COSTS							
DEMAND							
PRODUCTION	$40.19	375,434	N/A	921,187,272	.000408	$.01638	
TRANSMISSION	$25.49	375,434	N/A	921,187,272	.000408	$.01039	
DISTRIBUTION	$68.34	464,108	N/A	921,187,272	.000504	$.03443	
SUB-TOTAL						$.06120	
ENERGY							
PEAK	$.06226			411,954,948	44.720%	$.02784	
OFF-PEAK	$.03829			509,232,324	55.280%	$.02117	
SUB-TOTAL				921,187,272	100.000%	$.04901	
RATES							
CUSTOMER				6,139,619		$4.62	$28,355,035
ENERGY				921,187,272		$.07841	$72,230,294
FUEL CHG.						$.03181	
SSI							$-156,595
SUB-TOTAL							$100,438,732

RESIDENTIAL RATE R-1, REGULAR
VOLTAGE LEVEL: SEC.
(WINTER)

	MARGINAL COSTS	AVERAGE CLASS CP OR NCP	KW BILLING UNITS	KWH BILLING UNITS	COINCIDENCE FACTOR, OR PERCENTAGE TIME	WEIGHTED RATES	REVENUES
MARGINAL COSTS							
DEMAND							
PRODUCTION	$26.86	458,756	N/A	1,946,785,690	.000236	$.00633	
TRANSMISSION	$17.04	458,756	N/A	1,946,785,690	.000236	$.00401	
DISTRIBUTION	$102.43	605,050	N/A	1,946,785,690	.000311	$.03183	
SUB-TOTAL						$.04218	
ENERGY							
PEAK	$.06145			834,587,025	42.870%	$.02634	
OFF-PEAK	$.04024			1,112,198,665	57.130%	$.02299	
SUB-TOTAL				1,946,785,690	100.000%	$.04933	
RATES							
CUSTOMER						$4.62	
ENERGY				1,946,785,690		$.05971	$116,242,574
FUEL CHG.						$.03181	
SSI							$-291,912
SUB-TOTAL							$115,950,762
MISC. REVENUE							$382,552
TOTAL							$216,772,046
ALLOCATION							$216,793,915
DIFFERENCE							$-21,869

RESIDENTIAL RATE R-2, SSI RATES (SUMMER)	BILLING UNITS		WEIGHTED RATES	REVENUE LOSS
CUSTOMER	3,018		$2.77000	$5,584
ENERGY	4,815,538		$.04705	$151,015
SUB-TOTAL				$156,599
		DISCOUNT	40.000%	

RESIDENTIAL RATE R-2, SSI RATES (WINTER)	BILLING UNITS		WEIGHTED RATES	REVENUE LOSS
CUSTOMER	5,976		$2.77000	$11,055
ENERGY	11,756,979		$.03583	$280,757
SUB-TOTAL				$291,812
		DISCOUNT	40.000%	
TOTAL				$448,411

RESIDENTIAL RATE R-4, OPTIONAL TIME OF USE
VOLTAGE LEVEL: SEC.
(SUMMER)

	MARGINAL COSTS	AVERAGE CLASS CP OR NCP	KW BILLING UNITS	KWH BILLING UNITS	COINCIDENCE FACTOR, OR PERCENTAGE TIME	WEIGHTED RATES	REVENUES
MARGINAL COSTS							
DEMAND							
PRODUCTION	$40.19	375,434	N/A	411,954,948	.000911	$.03663	
TRANSMISSION	$25.49	375,434	N/A	411,954,948	.000911	$.02323	
DISTRIBUTION	$68.34	464,108	N/A	411,954,948	.001127	$.07700	
SUB-TOTAL						$.13686	
ENERGY							
PEAK	$.06226			411,954,948	100.000%	$.06226	
OFF-PEAK	$.03829			509,232,324	100.000%	$.03829	
SUB-TOTAL				921,187,272			
RATES							
CUSTOMER				6,139,619		$4.62	$28,365,038
ENERGY:							
PEAK				411,954,948		$.16731	$68,924,182
OFF-PEAK				509,232,324		$.00649	$3,304,918
FUEL CHG.						$.03181	
SUB-TOTAL							$100,594,138

RESIDENTIAL RATE R-4, OPTIONAL TIME OF USE
VOLTAGE LEVEL: SEC.
(SUMMER)

	MARGINAL COSTS	AVERAGE CLASS CP OR NCP	KW BILLING UNITS	KWH BILLING UNITS	COINCIDENCE FACTOR, OR PERCENTAGE TIME	WEIGHTED RATES	REVENUES
MARGINAL COSTS							
DEMAND							
PRODUCTION	$26.86	458,756	N/A	834,587,025	.000550	$.01477	
TRANSMISSION	$17.04	458,756	N/A	834,587,025	.000550	$.00936	
DISTRIBUTION	$102.43	605,050	N/A	834,587,025	.000725	$.07426	
SUB-TOTAL						$.09839	
ENERGY							
PEAK	$.06145			834,587,025	100.000%	$.06145	
OFF-PEAK	$.04024			1,112,198,665	100.000%	$.04024	
SUB-TOTAL				1,946,785,690			
RATES							
CUSTOMER				4,095,973		$4.62	
ENERGY:							
PEAK				834,587,025		$.12803	$106,852,177
OFF-PEAK				1,112,198,665		$.00844	$9,386,957
FUEL CHG.						$.03181	
SUB-TOTAL							$116,239,134
TOTAL							$216,833,271
ALLOCATION							$216,793,915
DIFFERENCE							$39,356

GENERAL SERVICE RATE G-1
VOLTAGE LEVEL: SEC.
(SUMMER)

	MARGINAL COSTS	AVERAGE CLASS CP OR NCP	KW BILLING UNITS	KWH BILLING UNITS	COINCIDENCE FACTOR, OR PERCENTAGE TIME	WEIGHTED RATES	REVENUES
MARGINAL COSTS							
DEMAND							
PRODUCTION	$40.19	110,843	N/A	139,846,274	.000793	$.03186	
TRANSMISSION	$25.49	110,843	N/A	139,846,274	.000793	$.02020	
DISTRIBUTION	$68.34	120,882	N/A	139,846,274	.000864	$.05908	
SUB-TOTAL						$.11114	
ENERGY							
PEAK	$.06226			84,271,365	60.260%	$.03752	
OFF-PEAK	$.03829			55,574,909	39.740%	$.01522	
SUB-TOTAL				139,846,274	100.000%	$.05274	
RATES							
CUSTOMER				595,747		$.00	$0
ENERGY				139,846,274		$.11820	$16,529,830
FUEL CHG.						$.03181	
SUB-TOTAL							$16,529,830

GENERAL SERVICE RATE G-1
VOLTAGE LEVEL: SEC.
(WINTER)

	MARGINAL COSTS	AVERAGE CLASS CP OR NCP	KW BILLING UNITS	KWH BILLING UNITS	COINCIDENCE FACTOR, OR PERCENTAGE TIME	WEIGHTED RATES	REVENUES
MARGINAL COSTS							
DEMAND							
PRODUCTION	$26.85	73,607	N/A	263,188,549	.000280	$.00751	
TRANSMISSION	$17.04	73,607	N/A	263,188,549	.000280	$.00476	
DISTRIBUTION	$102.43	101,443	N/A	263,188,549	.000385	$.03948	
SUB-TOTAL						$.05176	
ENERGY							
PEAK	$.06145			153,965,301	58.500%	$.03595	
OFF-PEAK	$.04024			109,223,248	41.500%	$.01670	
SUB-TOTAL				263,188,549	100.000%	$.05265	
RATES							
CUSTOMER				339,768		$.00	
ENERGY				263,188,549		$.06499	$17,101,992
FUEL CHG.						$.03181	
SUB-TOTAL							$17,101,992
MISC. REVENUE							$-4,149
TOTAL							$33,627,673
ALLOCATION							$33,625,720
DIFFERENCE							$1,954

GENERAL SERVICE RATE G-2
VOLTAGE LEVEL: SEC.
(SUMMER)

	MARGINAL COSTS	AVERAGE CLASS CP OR NCP	KW BILLING UNITS	KWH BILLING UNITS	COINCIDENCE FACTOR, OR PERCENTAGE TIME	WEIGHTED RATES	REVENUES
MARGINAL COSTS							
DEMAND							
PRODUCTION	$40.19	852,000	4,840,413	N/A	.176018	$7.07461	
TRANSMISSION	$25.49	852,000	4,840,413	N/A	.176018	$4.48663	
DISTRIBUTION	$68.34	891,353	4,840,413	N/A	.184148	$12.58535	
SUB-TOTAL						$24.14659	
ENERGY							
PEAK	$.06226			812,948,621	52.943%	$.06226	
OFF-PEAK	$.03829			722,575,298	47.057%	$.03829	
SUB-TOTAL				1,535,523,919	100.000%		
RATES							
CUSTOMER				294,127		$.00	$0
DEMAND				4,840,413		$19.28	$93,323,163
ENERGY 175HRS USE				812,948,621		$.03046	$24,762,415
ENERGY EXCESS				722,575,298		$.00649	$4,689,514
FUEL CHG.						$.03181	
SUB-TOTAL							$122,775,091

GENERAL SERVICE RATE G-2
VOLTAGE LEVEL: SEC.
(WINTER)

	MARGINAL COSTS	AVERAGE CLASS CP OR NCP	KW BILLING UNITS	KWH BILLING UNITS	COINCIDENCE FACTOR, OR PERCENTAGE TIME	WEIGHTED RATES	REVENUES
MARGINAL COSTS							
DEMAND							
PRODUCTION	$26.86	738,585	9,377,913	N/A	.078758	$2.11569	
TRANSMISSION	$17.04	738,585	9,377,913	N/A	.078758	$1.34174	
DISTRIBUTION	$102.43	885,400	9,377,913	N/A	.094413	$9.67076	
SUB-TOTAL						$13.12819	
ENERGY							
PEAK	$.06145			1,521,158,987	51.860%	$.06145	
OFF-PEAK	$.04024			1,412,034,277	48.140%	$.04024	
SUB-TOTAL				2,933,193,264	100.000%		
RATES							
CUSTOMER				166,600		$.00	
DEMAND				9,377,913		$10.49	$98,374,307
ENERGY 175HRS USE				1,521,158,987		$.02964	$45,087,152
ENERGY EXCESS				1,412,034,277		$.00844	$11,917,569
FUEL CHG.						$.03181	
SUB-TOTAL							$155,379,029
593 AND 599 REVENUE				12,782,316		$.06241	$797,776
TOTAL							$278,951,896
ALLOCATION							$278,903,536
DIFFERENCE							$48,360

GENERAL SERVICE RATE G-3
VOLTAGE LEVEL: HI TEN.
(SUMMER)

	MARGINAL COSTS	AVERAGE CLASS CP OR NCP	KVA BILLING UNITS	KWH BILLING UNITS	COINCIDENCE FACTOR, OR PERCENTAGE TIME	WEIGHTED RATES	REVENUES
MARGINAL COSTS							
DEMAND							
PRODUCTION	$36.28	499,092	2,508,451	N/A	.182361	$6.61523	
TRANSMISSION	$23.01	499,092	2,508,451	N/A	.182361	$4.19529	
DISTRIBUTION	$20.97	505,948	2,508,451	N/A	.189032	$3.96438	
SUB-TOTAL						$14.77489	
ENERGY							
PEAK	$.05612			478,587,401	47.411%	$.05612	
OFF-PEAK	$.03558			530,866,438	52.589%	$.03558	
SUB-TOTAL				1,009,453,839	100.000%		
RATES							
CUSTOMER				4,742		$.00	$0
DEMAND				2,508,451		$14.77	$37,049,824
ENERGY PEAK				478,587,401		$.03331	$15,941,745
ENERGY OFF-PEAK				530,866,438		$.00517	$2,744,579
FUEL CHG.						$.02181	
SUB-TOTAL							$55,736,150

GENERAL SERVICE RATE G-3
VOLTAGE LEVEL: HI TEN.
(WINTER)

	MARGINAL COSTS	AVERAGE CLASS CP OR NCP	KW BILLING UNITS	KWH BILLING UNITS	COINCIDENCE FACTOR, OR PERCENTAGE TIME	WEIGHTED RATES	REVENUES
MARGINAL COSTS							
DEMAND							
PRODUCTION	$23.98	412,999	4,521,500	N/A	.086171	$2.06631	
TRANSMISSION	$15.21	412,999	4,521,500	N/A	.086171	$1.31043	
DISTRIBUTION	$31.25	457,958	4,521,500	N/A	.095551	$2.98613	
SUB-TOTAL						$6.36287	
ENERGY							
PEAK	$.05505			860,311,562	47.044%	$.05505	
OFF-PEAK	$.03741			968,432,256	52.956%	$.03741	
SUB-TOTAL				1,828,743,818	100.000%		
RATES							
CUSTOMER				$3,175		$.00	
DEMAND				4,521,500		$6.36	$28,756,742
ENERGY PEAK				860,311,562		$.03194	$27,392,320
ENERGY OFF-PEAK				968,432,256		$.00766	$7,437,560
FUEL CHG.						$.03181	
SUB-TOTAL							$63,586,622
MISC. REVENUES							$-14,916
TOTAL							$115,307,955
ALLOCATION							$119,311,069
DIFFERENCE							$-3,112

STREET LIGHTING S-1, S-2 AND S-3
VOLTAGE LEVEL: SEC.
(SUMMER)

	MARGINAL COSTS	AVERAGE CLASS CP OR NCP	KW BILLING UNITS	KWH BILLING UNITS	COINCIDENCE FACTOR, OR PERCENTAGE TIME	WEIGHTED RATES
MARGINAL COSTS						
DEMAND						
PRODUCTION	$40.15	856	N/A	48,434,891	.000018	$.00071
TRANSMISSION	$25.45	856	N/A	48,434,891	.000018	$.00045
DISTRIBUTION	$68.34	32,304	N/A	48,434,891	.000667	$.04558
SUB-TOTAL						$.04674
ENERGY						
PEAK	$.06226			11,939,764	24.651%	$.01535
OFF-PEAK	$.03829			36,495,127	75.349%	$.02885
SUB-TOTAL				48,434,891	100.000%	$.04420
RATES						
CUSTOMER				0		$.00
ENERGY				48,434,891		$.05914
FUEL CHG.						$.03181

STREET LIGHTING S-1, S-2 AND S-3
VOLTAGE LEVEL: SEC.
(WINTER)

	MARGINAL COSTS	AVERAGE CLASS CP OR NCP	KW BILLING UNITS	KWH BILLING UNITS	COINCIDENCE FACTOR, OR PERCENTAGE TIME	WEIGHTED RATES
MARGINAL COSTS						
DEMAND						
PRODUCTION	$26.86	21,263	N/A	101,750,818	.000209	$.00561
TRANSMISSION	$17.04	21,263	N/A	101,750,818	.000209	$.00356
DISTRIBUTION	$102.43	33,605	N/A	101,750,818	.000330	$.03383
SUB-TOTAL						$.04300
ENERGY						
PEAK	$.06145			25,201,162	24.768%	$.01522
OFF-PEAK	$.04024			76,549,656	75.232%	$.03027
SUB-TOTAL				101,750,818	100.000%	$.04549
RATES						
CUSTOMER				0		$.00
ENERGY				101,750,818		$.05669
FUEL CHG.						$.03181

ALLOCATION OF DPU ADJUSTMENTS FROM TOTAL ELECTRIC TO RETAIL

SCHEDULE 16

ADJUSTMENT NAME	TOTAL ELECTRIC ADJUSTMENT PER DPU	ALLOCATOR FROM (SCHEDULE, PAGE, LINE)	RETAIL ALLOCATOR	RETAIL ELECTRIC ADJUSTMENT PER DPU (E X H)
RATE BASE				
PILGRIM RECONVEYANCE AMORT.	$-448.000	4.1A.84	97.392%	$-436.315
PRE-1983 SNFDC	$-2.897.544		100.000%	$-2.897.544
SALES OF UTILITY PROPERTY	$-1.334.413		100.000%	$-1.334.413
SALES OF UTILITY PROPERTY	$-897.000		100.000%	$-897.000
COST OF SERVICE				
FUEL & PURCHASED POWER	$6.587.000	4.1A.112	97.384%	$6.414.693
BOOKING ERRORS	$-1.161.000	C.B..A-8	99.225%	$-1.152.000
BOOKING ERRORS	$28.801	C.B..A-8	98.938%	$28.495
BOOKING ERRORS	$914.000	C.B..A-8	99.015%	$905.000
COAL CONVERSION EXPENSES	$0	4.1A.112	97.384%	$0
GAS CONVERSION EXPENSES	$-3.287.000	5.1A.40	97.457%	$-3.203.427
TEWKSBURY-WOBURN TRANS. LINES	$-989.000	4.1A.155	97.363%	$-962.923
NEW BOST OUTAGE EXPENSES TRANSFORMER RENTAL	$-1.221.741	4.1A.105	97.087%	$-1.186.152
NUCLEAR INTANGIBLE	$-1.040.000	5.1A.72	97.392%	$-1.012.875
RATE CASE EXPENSES	$25.500	4.1A.125	100.000%	$25.500
PILGRIM 1 DECOM. FUND	$0	5.1A.75	97.392%	$0
PILGRIM OUTAGE EXPENSES	$3.762.213	4 1A 110	97.392%	$3.664.087
UNCOLLECTIBLES	$-487.000	4.1A.220	100.000%	$-487.000
CHARITABLE DONATIONS	$-1.033.000	4.1A.123	97.765%	$-1.009.912
EEI MEMBERSHIP DUES & EXPENSES	$-291.000	4.1A.127	98.558%	$-286.803
EEI MEMBERSHIP DUES & EXPENSES	$-39.000	13.6A.848	98.104%	$-38.260
EPRI LIFE EXTENSION	$-184.000	ACCT. 506	97.433%	$-179.277
EPRI LIFE EXTENSION	$184.000	ACCT. 506	97.433%	$179.277
ANNUALIZED TRANS. EXPENSE	$-6.589.000	4.1A.124	97.392%	$-6.417.147
STORM COSTS, 1985	$50.000	4.1A.75	99.989%	$49.995
IMPACT 2000 HOUSE WRITE-OFF	$-392.000	ACCT. 909	100.000%	$-392.000
IMPACT 2000 HOUSE ADVERTISING	$-334.000	ACCT. 909	100.000%	$-334.000
DC SYSTEM DISCONTINUANCE	$1.482.000	5.1A.110	99.424%	$1.473.466
WAGE AND SALARY ADJUSTMENTS	$608.000	4.1A.20	98.559%	$599.238
PROPERTY TAX	$-3.632.000	5.1A.230	98.285%	$-3.569.704
SETTLEMENT WRITEOFFS	$-393.000		100.000%	$-393.000
RENT FROM ELECTRIC PROPERTY	$-268.000	10.1A.228	99.988%	$-267.969
PURCHASED POWER EXPENSE TRANSFER	$7.624.000	4.1A.124	97.392%	$7.425.152

XIV. ORDER

Accordingly, after due notice, hearing and consideration, it is

ORDERED: That tariffs MDPU 710, Experimental Customer Interruptible Rate SC 1, and 711, Experimental Interruptible Rate SC 2, filed with the Department by the Boston Edison Company on December 2, 1985, to become effective January 1, 1986 by the Boston Edison Company be and hereby are DISALLOWED; and it is

FURTHER ORDERED: That tariffs MDPU Nos. 712, Terms and Conditions; 713, General Service Rate 1; 714, General Service Rate 2, General Service Rate 3; 715, General Service Rate G-2A; 716, General Service Rate G-3; 717, Optional Time-of-Use Rate T-1; 718, Time-of-Use Rate T-2; 719, Residence Rate 1; 720, Residence Rate 2; 721, Residence Rate R-3; 722, Optional Time-of-Use Rate R-4; 723, Street Lighting Energy Rate S-1; 723, Street Lighting Energy Rate S-2; 725, Outdoor Lighting Rate S-3; 726, Auxiliary Services Charges; 543, Conservation Service Charge; 727, Direct Current Charge; 687, Fuel and Purchased Power Adjustment; 728, Miscellaneous Charges; and 729, Qualifying Facility Power Purchase Rate, filed with the Department on December 17, 1985, by the Boston Edison Company,

to become effective January 1, 1986 be and hereby are DISALLOWED; and it is

FURTHER ORDERED: That Boston Edison Company shall file new schedules of rates and charges designed to produce additional gross revenues for its retail operations of $77,323; and it is

FURTHER ORDERED: That Boston Edison Company shall file all rates and charges required by the Order, and shall design all such rates in compliance with this Order; and it is

FURTHER ORDERED: That Boston Edison Company shall comply with all other orders and directives contained in this Order; and it is

FURTHER ORDERED: That the new rates may apply to electricity consumed on or after the date of this Order, but unless otherwise ordered by the Department, shall not become effective earlier than seven (7) days after they are filed with supporting data demonstrating that such rates are in compliance with this Order.

By Order of the Department,

/s/ PAUL F. LEVY

Paul F. Levy, Chairman

/s/ ROBERT J. KEEGAN

Robert J. Keegan, Commissioner

/s/ BERNICE K. McINTYRE

Bernice K. McIntyre, Commissioner

A true copy
Attest;

Mary L. Cottrell
Secretary

Appeal as to matters of law from any final decision, order or ruling of the Commission may be taken to the Supreme Judicial Court by an aggrieved party in interest by the filing of a written petition praying that the order of the Commission be modified or set aside in whole or in part.

Such petition for appeal shall be filed with the Secretary of the Commission within twenty days after the date of service of the decision, order or ruling of the Commission, or within such further time as the Commission may allow upon request filed prior to the expiration of the twenty days after the date of service of said decision, order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by Filing a copy thereof with the clerk of said court. (Sec. 5, Chapter 25, G.L. Ter. Ed., as most recently amended by Chapter 485 of the Acts of 1971).